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BEFORE THE ARIZONA CORPORATION COMMISSION

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COMMISSIONER

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	Docket No. G-04204A-08-0571

NOTICE OF FILING DIRECT TESTIMONY

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Direct Testimony of Ralph C. Smith, Frank W. Radigan, and William A. Rigsby in the above-referenced matter.

RESPECTFULLY SUBMITTED this 8th day of June, 2009.

Daniel W. Pozefsky
Chief Counsel

Arizona Corporation Commission
DOCKETED

JUN - 8 2009

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AN ORIGINAL AND THIRTEEN COPIES
of the foregoing filed this 8th day
of June, 2009 with:

Docket Control
Arizona Corporation Commission
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COPIES of the foregoing hand delivered/
mailed this 8th day of June, 2009 to:

Dwight D. Nodes
Asst. Chief Administrative Law Judge
Hearing Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Janice Alward, Chief Counsel
Legal Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Ernest Johnson, Director
Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Raymond S. Heyman, Esq.
Phillip J. Dion, Esq.
Michelle Livengood, Esq.
UniSource Energy Corporation
One South Church, Suite 200
Tucson, Arizona 85701

Michael W. Patten, Esq.
Timothy Sabo, Esq.
Roshka, DeWulf & Patten, PLC
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004

Nicholas J. Enoch
Jarrett J. Haskovec
Lubin & Enoch, P.c.
349 North Fourth Avenue
Phoenix, AZ 85003

Cynthia Zwick
1940 E. Luke Avenue
Phoenix, AZ 85016

By Ernestine Gamble
Ernestine Gamble
Secretary to Daniel W. Pozefsky

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
Kristen K. Mayes – Chairman
Gary Pierce
Sandra D. Kennedy
Paul Newman
Bob Stump

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	)	**DOCKET No. G-04204A-08-0571**

DIRECT TESTIMONY

OF

FRANK W. RADIGAN

ON BEHALF OF
RESIDENTIAL UTLITIY CONUSMER OFFICE OF ARIZONA

Phoenix, Arizona
June 8, 2009

DIRECT TESTIMONY OF FRANK W. RADIGAN
EXECUTIVE SUMMARY

1) The Company's proposed cost of service study uses a Commission accepted method to allocate costs. The Company has proposed to allocate costs on an across the board basis except for the CARES customers who receive no increase. In these uncertain economic times an equal sharing of the rate increase is reasonable. The proposed revenue allocation is shown on Exhibit 3 and summarized below:

Class of Service	Present Revenue	Proposed Revenue	Proposed Increase	Proposed Percent Increase
Residential Service	$36,600,943	$37,190,974	$590,030	1.6%
Commercial Gas Service	$9,910,680	$10,076,399	$165,720	1.7%
Industrial Gas Service	$246,712	$250,838	$4,125	1.7%
Public Authority Gas Servic	$1,778,118	$1,807,850	$29,732	1.7%
Special Gas Light Service	$66,940	$68,059	$1,119	1.7%
Irrigation Service	$33,865	$34,431	$566	1.7%
Transportation Customers	$3,036,509	$3,086,270	$49,761	1.6%
Total	$51,673,767	$52,514,821	$841,054	1.6%

2) The Company's proposal not to increase the rates for the CARES customers is reasonable and abides by recent Commission treatment to these customers of holding them harmless from rate increase.

3) The Company's proposed rate design that would phase in a 71% increase in the residential customer charge over three years should be rejected. Instead, the proposed increase in the customer charges for what the Company describes as Year 1 are reasonable as they increase

rates towards the indicated cost of service but do not overly increase rates. My proposed customer charges are summarized in the table below.

	Present	Proposed	Increase	% Increase
Residential	$ 8.50	$ 10.00	$ 1.50	18%
Small Commercial & Industrial	13.50	15.50	2.00	15%
Large Commerical and Industrial	100.00	105.00	5.00	5%
Irrigation Service	13.50	15.50	2.00	15%

4) The impact for a Residential Customer from this proposed revenue allocation and rate design is as follows. The customer charge is proposed to increase from $8.50 per month to $10 per month and the commodity charge is proposed to decrease slightly from $0.3270 per therm to $0.3027 per therm. The average bill for the Residential Class is 45 therms per month and a customer with such average usage will see an increase of 1.7%, which is the class average increase. Detailed bill impacts from each class are shown on Schedule H-4 of Exhibit 3 to my testimony.

I. INTRODUCTION

Q. Please state your name, position and business address.

A. Frank W. Radigan. I am a principal in the Hudson River Energy Company, a consulting firm providing services to the utility industry and specializing in the fields of rates, planning, and utility economics. My office address is 237 Schoolhouse Road, Albany, New York 12203.

Q. Would you please summarize your education and business experience?

A. I received a Bachelor of Science degree in Chemical Engineering from Clarkson College of Technology in Potsdam, New York (now Clarkson University) in 1981. I received a Certificate in Regulatory Economics from the State University of New York at Albany in 1990. From 1981 through February 1997, I served on the Staff of the New York State Public Service Commission in the Rates and System Planning sections of the Power Division and in the Rates Section of the Energy and Water Division. My responsibilities included resource planning and the analysis of rates, depreciation rates and tariffs of electric, gas, water and steam utilities in the State and encompassed rate design and performing embedded and marginal cost of service studies as well as depreciation studies.

Before leaving the Commission, I was responsible for directing all engineering staff during major proceedings including those relating to rates, integrated resource planning and environmental impact studies. In February 1997, I left the Commission and joined the firm of Louis Berger & Associates as a Senior Energy Consultant. In December 1998, I formed my own Company.

In my 27 years of experience, I have testified as an expert witness in utility rate proceedings on more than 80 occasions before various utility regulatory bodies including the Arizona Corporation Commission, the Connecticut Department of Utility Control, the Maryland Public Service Commission, the Massachusetts Department of Telecommunications and Energy, the Michigan Public Service Commission, the New York State Public Service Commission, the New York State Department of Taxation and Finance, the Nevada Public Utilities Commission, the Public Utilities Commission of Ohio, the Rhode Island Public Utilities Commission, the Vermont Public Service Board, and the Federal Energy Regulatory Commission.

I currently advise a variety of Regulatory Commissions, consumer advocates, municipal utilities and industrial customers concerning rate matters, including wholesale electricity rates and electric transmission rates. A summary of my qualifications and experience is included as Exhibit 1.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Residential Utility Consumer Office of Arizona ("RUCO").

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes. I have testified before the Commission previously on four occasions. I testified before the Commission in the most recent UNS Electric, Inc. rate case (Docket No. E-04204A-06-0783), the most recent Tucson Electric Power Company rate case (Docket No. E-01933A-07-0402), the most recent Southwest Gas Company rate case (Docket No. G-01551A-07-0504) and the most recent Arizona Public Service Company rate case (Docket No. E-01345A-08-0172).

Q. What is the purpose of the testimony you are presenting?

A. I have been asked to discuss the reasonableness of UNS Gas, Inc.'s (UNS or the Company) proposed cost of service allocation and rate design.

Q. Could you please summarize your testimony?

A. Yes, based on my review of the filing I have the following conclusions and recommendations:

1) The Company's proposed cost of service study uses a Commission accepted method to allocate costs. The Company has proposed to allocate costs on an across the board basis except for the CARES customers who receive no increase. In these uncertain economic times an equal sharing of the rate increase is reasonable.

2) The Company's proposed rate design that would phase in a 71% increase in the residential customer charge over three years should be rejected. Instead, the proposed increase in the customer charges for what the Company describes as Year 1 are reasonable as they increase rates towards the indicated cost of service but do not overly increase rates.

3) The Company's proposal not to increase the rates for the CARES customers is reasonable and abides by recent Commission treatment to these customers of holding them harmless from rate increase.

Q. Could you please comment on the Company's cost of service study and revenue allocation?

A. Yes. The Cost of Service Study was prepared and presented by Company Witness Bentley Erdwurm and is described in his pre-filed testimony at pages 9-14. Mr. Erdwurm performed a traditional embedded cost of service study using the Proportional Responsibility method. This method uses the respective class' share of total load in each of the twelve months for the test-year to develop an allocation factor to assign costs. (Erdwurm PFT, page 17) The Proportional Responsibility method drives many significant costs in the class cost-of-service study model (Ibid). The Proportional Responsibility Method has been used in other recent rate case filings before the Commission including the Company's last rate case (Ibid). I have reviewed the allocation factors used in the study and the supporting data used to develop them. The results of the cost of service study are presented below:

UNS Gas, Inc.
Cost of Service Study Results

	Rate of Return	Indexed Rate of Return
Residential	5.6%	0.87
Total Commercial	11.5%	1.80
Total Industrical	1.4%	0.23
Total Public Authority	7.4%	1.16
Special Gas Light Service	32.3%	5.08
Irrigation	9.2%	1.44
Total Company	6.4%	1.00

Even though there is some disparity amongst classes in the indicated rates of return, the Company has proposed to allocate revenues on an across-the-board basis. Mr. Erdwurm argues that this allocation helps mitigate the adverse rate impact on any class (Erdwurm PFT, page 17). I agree and support his allocation.

Q. Could you please comment on the Company's proposed rate design?

A. Yes, as noted by Company Witness Erdwurm the Company's primary objectives in rate design is to more equitably collect its fixed costs (Erdwurm PFT page 18). UNS proposes an increase in monthly customer charges to levels that better match the true customer-related costs, as indicated by the class cost-of-service study (Ibid). As Mr. Erdwurm he is seeking to move the customer costs towards the "bare-bones" customer charge. "Bare-bones" customer charges restrict the customer classification to metering, meter-reading, service (service drop) to the specific customer, customer service and billing (Ibid). According to the study, the "bare bones" monthly customer charges are calculated to be $18.15 for residential service, approximately $19.00 for small commercial/industrial customers and approximately $220.00 for large commercial/industrial customers (Ibid).

Under Mr. Erdwurm's proposal for residential service, the increases will be phased-in over three years. Upon approval of this rate case the customer charge will increase from $8.50 per month to $10 per month. One year after rates are approved the customer charge will automatically increase from $10 to $12 per month and two years after rates are approved in this case the customer charge will automatically increase from $12 to $14 per month. Even after the three year phase in Mr. Erdwurm argues that the residential customer charge will still be below the "bare-bones" customer charge of $18.15. Customer charges for non-residential classes generally also are raised closer to levels indicated by the class cost-of-service study but there is no automatic phase in of cost increases. (Erdwurm PFT pages 18-19).

Q. Do you agree with Mr. Erdwurm's proposal on the Residential Customer Charge?

A. No. While the proposed customer charges are cost-based, the company has ignored the rate design principles of rate stability. Automatic rate increases are generally not appreciated by customers and this is especially true when it comes to rate increases that can be viewed as a large increase. Mr. Erdwurm's automatic rate increase in the second and third year will increase a small customer's bill by 40%. Outside of a rate case this large of an increase will undoubtedly cause an increase in customer complaints.

Q. Mr. Erdwurm argues that the very nature of UNS' service territory causes problems that must be addressed though the customer charge, can you comment on that?

A. Yes. In his testimony Mr. Erdwurm states given that natural gas usage is largely driven largely by weather, the Company's current rates have resulted in customers in cooler areas (i.e., districts with more heating degree days like Flagstaff) subsidizing those living in warmer areas (i.e., districts with less heating degree days like Lake Havasu City). He states that customers in the coldest corners of the service territory – those affected most by rising costs on the volumetric, gas commodity portion of their bills during home heating season – have borne the additional burden of subsidizing the fixed cost of serving customers who spend their winters in far more moderate climates (Erdwurm PFT pages 20 and 21). This argument is a red herring. Mr. Erdwurm's analysis only looks at the net margin from sales from small and large customers and notes that a large customer contributes more than a small. Large customers, however, also are served by large mains and can contribute more to peak indicating that it costs more to serve them. This can only be done through a cost of service study. If Mr. Erdwurm truly believes that UNS should have District rates, then he should present a study which actually studies if there are cost differences to serve the two Districts.

Q. Mr. Erdwurm argues that recovery of fixed costs in the customer charge as compared to the volumetric charge is preferred, do you disagree?

A. From the utility perspective that is true as they want to be able to recover most of their fixed costs up front. That said, however, in the rate case the Company's rates are designed to recover the total revenue requirement. Thus, the only risk to the Company is between rate cases if customer usage changes to due warmer than normal weather or customer conservation. On the other hand, there can be colder than average weather and customer growth can occur and this would help the Company. Thus, a balance must be reached that treats the Company and the customer fairly.

Q. What do you recommend be done with the customer charges?

A. A reasonable balance is one that recognizes 1) the customer cost indicated by the cost of service study, 2) rate stability for customers and 3) increasing the amount of money recovered though the fixed charge. To this end I recommend that the Company's proposed customer charge for year one allowed to become effective with no automatic increases allowed. Any further changes to the customer charge would be analyzed again in the next rate case. A summary of the present and proposed customer charges are presented in the table below.

	Present	Proposed	Increase	% Increase
Residential	$ 8.50	$ 10.00	$ 1.50	18%
Small Commercial & Industrial	13.50	15.50	2.00	15%
Large Commerical and Industrial	100.00	105.00	5.00	5%
Irrigation Service	13.50	15.50	2.00	15%

While the percentage increase appears relatively high given the RUCO is recommending a 1.6% overall increase, the dollar increases are low, however, with a residential customer's bill increase by only $1.50 per month. In addition, for each class the average customer receives a reasonable increase. For example, the average usage for a residential customer 45 therms per month and this customer will see an increase in their bill of 1.7% which is almost equal to the overall average increase being given to the Company of 1.6%.

Q. Please discuss the bill impact of your proposed rates for the Residential Class.

A. The customer charge is proposed to increase from $8.50 per month to $10 per month and the commodity charge is proposed to decrease slightly from $0.3270 per therm to $0.3027 per therm. The average bill for this class is 45 therms per month and a customer with such average usage will see an increase of 1.7% which is the class average increase. Typical bills for the full range of residential usage are included in Exhibit 3 (RUCO UNS Gas Schedule H, Schedule H-4, page 1).

Q. Please discuss the bill impact of your proposed rates for the Small Commercial Class (C-20).

A. The customer charge is proposed to increase from $13.50 per month to $15.50 per month and the commodity charge is proposed to decrease slightly from $0.2638 per therm to $0.2600 per therm. The average bill for this class is 214 therms per month, and a customer with that usage will see an increase of 1.7% which is the class average increase.

Q. Please discuss the bill impact of your proposed rates for the Large Volume Industrial (I-32).

A. The customer charge is proposed to increase from $100.50 per month to $105.00 per month and the commodity charge is proposed to increase slightly from $0.0952 per therm to $0.0966 per therm. The average bill for this class is approximately 20,000 therms per month, and a customer with that usage will see an increase of 1.7%, which is the class average increase.

Q. Please discuss the bill impact of your proposed rates for the CARES Residential Customers (R-12).

A. The Company has proposed to retain the CARES pricing plan, and proposes to hold the customer charge and the non-commodity volumetric charges at the current levels (Erdwurm PTF page 26). I agree this has been the adopted method in the recent TEP rate case and what staff proposed in the ongoing Arizona Public Service rate case. As shown on Exhibit 3, Schedule H-4, page 2, these customers will see no increase.

Q, Does this conclude your testimony?

A. Yes.

Exhibit 1
Resume of Frank W. Radigan

FRANK W. RADIGAN

EDUCATION

B.S., Chemical Engineering -- Clarkson University, Potsdam, New York (1981)

Certificate in Regulatory Economics -- State University of New York at Albany (1990)

SUMMARY OF PROFESSIONAL EXPERIENCE

1998–Present **Principal, Hudson River Energy Group, Albany, NY** -- Provide research, technical evaluation, due diligence, reporting, and expert witness testimony on electric, steam, gas and water utilities. Provide expertise in electric supply planning, economics, regulation, wholesale supply and industry restructuring issues. Perform analysis of rate adequacy, rate unbundling, cost-of-service studies, rate design, rate structure and multi-year rate agreements. Perform depreciation studies, conservation studies and proposes feasible conservation programs.

1997–1998 **Manager Energy Planning, Louis Berger & Associates, Albany, NY** – Advised clients on rate setting, rate design, rate unbundling and performance based ratemaking. Served a wide variety of clients in dealing with complexities of deregulation and restructuring, including OATT pricing, resource adequacy, asset valuation in divestiture auctions, transmission planning policies and power supply.

1981–1997 **Senior Valuation Engineer, New York State Public Service Commission, Albany, NY** – Starting as a Junior Engineer and working progressively through the ranks, served on the Staff of the New York State Department of Public Service in the Rates and System Planning Sections of the Power Division and in the Rates Section of the Gas and Water Division. Responsibilities included the analysis of rates, rate design and tariffs of electric, gas, water and steam utilities in the State and performing embedded and marginal cost of service studies. Before leaving the Commission, was responsible for directing all engineering staff during major rate proceedings.

FIELDS OF SPECIALIZATION

Electric power restructuring, wholesale and retail wheeling rates, analysis of load pockets and market power, divestiture, generation planning, power supply agreements and expert witness testimony, retail access, cost of service studies, rate unbundling, rate design and depreciation studies.

PROJECT HIGHLIGHTS

Wholesale Commodity Markets

Transmission Expansion Planning – Various Utilities -- Member of Transmission Expansion Advisory Committee in the New England Power Pool – the Committee is charged with the study of transmission expansion needs in the deregulated New England electric market. Ongoing

Locational Based Pricing – Reading Municipal Light Department -- Using GE multi-area production simulation model (MAPS), analyzed New England wholesale power market to cost differences between various generators and load centers. 2003

Merchant Plant Analysis – Confidential client – Using GE multi-area production simulation model (MAPS), analyzed New York City wholesale power market to determine economics of restructuring PURPA era contract to market priced contract. 2002

Market Price Forecasting – El Paso Merchant Energy – Analyzed New England power market using MAPS for purpose of pricing natural gas supply in order to ensure that plant was dispatched at 70% capacity factor as required under its gas supply contract. 2002

Market Price Analysis – Novo Windpower – Analyzed hourly market price data in New York for each load zone in State in order to optimize location of new wind power projects. 2002

Gas Aggregation – Village of Ilion – Advised client on costs/benefits of aggregating residential gas customers for purpose of gas purchasing. 2002

Gas Procurement – Albany County, New York – Assisted client in analysis of economics of existing gas purchase contract; negotiated termination of contract; designing request for proposal for new natural gas supply. 2000

HQ Prudence Review – Selected by Vermont Public Service Board to perform prudence review power supply contract between Hydro Quebec and Central Vermont Public Service Corporation. 1998

Wholesale Power Supply – Prepared comprehensive RFP to optimize power supply for Solvay municipal utility by complementing existing low cost power supplies in order to entice new industrial load to locate within Village. 1997

Analysis of Load Pockets and Market Power – Performed analysis of load pockets and market power in New York State; determined physical and financial measures that could mitigate market power. 1996

Study of IPP Contracts and Impacts in New York Performed study to determine rate impacts of power purchase contracts entered into by investor owned utilities and independent power producers (IPPs); separately measured rate impacts resulting from statewide excess-capacity; determined level of non-optimal reserves for each utility. 1995

Power Purchase Contract Policies and Procedures – Directed NYSPSC Staff teams in formulation of short- and long-run avoided cost estimates (LRACs) using production simulation model (PROMOD); forecasted load and capacity requirements; developed utility buy-back rates; presented expert witness testimony on buy-back rate estimates and calculation methodologies, thereby implementing curtailment of IPPs as allowed under PURPA. 1990-1994

Integrated Resource Planning - Led NYSPSC Staff team's examination of each utility's IRP process and examination of impacts of processes and regulatory policies influencing the decision making process. 1994

Intrastate Wheeling Commission Transmission Analysis and Assessment – Chairman of NYSPSC Proceeding to examine plans for meeting future electricity needs in New York State. Addressed measures for estimating and allocating costs of wheeling, including embedded cost, short-run marginal cost and long run incremental cost methods. 1990

Rate Setting

Rate Case Cost of Service Study – Stowe Electric Department, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the Vermont Public Service Board. 2009

Rate Case Cost of Service Study – Village of Greene, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Rate Case Cost of Service Study – Village of Bath, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Rate Case Cost of Service Study – Village of Richmondville, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Economic Development Rate – Massena Electric Department – For municipal electric utility, developed tariffs for economic development rates for new or expanded load.

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Study – Pascoag Utility District – Reviewed the application of the Power Authority of the State of New York to increase rates to its wholesale power customers. 2003

Rate Study - Kennebunk Power and Light Department – Performed rate study of new multi-year wholesale power contract against existing rates to determine impact on overall revenue recovery and cash flows of utility. 2003

Rate Case Cost of Service Study – Village of Arcade, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Philadelphia, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Case Cost of Service Study – Fillmore Gas Company – For small natural gas local distribution company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Rowlands Hollow Water Works – For small water company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Standby Rates – Independent Power Producers of New York – Analyzed reasonableness of proposed standby rates of Niagara Mohawk Power Corporation; proposed alternate rate designs; participated in settlement negotiations for new rates. 2002

Economic Development Rates – Pascoag Utility District – Designed new cost based economic development rates charged to large industrial customer contemplating locating within the municipality. 2002

Municipalization Study – Kennebunk Power and Light Department – Performed economic analysis of municipal utility serving remaining portions of Village not already served; performed valuation of the plant currently owned by Central Maine Power. 2001

Water Rate Study – Pascoag Utility District – Performed cost of service study for water utility; presented alternate methods of funding revenue requirement. 2001

Pole Attachment Rates – Middleborough Gas and Electric Department – Designed cost based pole attachment rates charged to CATV customers. 2000

ISO Service Tariff -- On behalf of three municipal utilities, analyzed cost basis and proposed rate design of ISO

Service Tariffs. 2000

Pole Attachment Rates – City of Farmington, New Mexico municipal electric department – Designed cost based pole attachment rates for CATV customers. 1999

OATT Rates – On behalf of four municipal utilities in New England – Developed cost based annual revenue requirements for regional network transmission rates; represent utilities before ISO New England committees on transmission rate setting issues. 1998-2004

Consolidated Edison Restructuring – Member NYPSC Staff team – Negotiated major restructuring settlement with Consolidated Edison, which decreased utility's rates by $700 million over five years; implemented retail access program; performed rate unbundling; divestiture of utility generation and the allowance of the formation of a holding company; accelerated depreciation of generation; established customer education programs on restructuring; established service quality and service reliability incentive to ensure that provision of electric service will diminish as competitive market emerges. The agreement served as the template for restructuring in New York. 1997

Cost-of-service Review and Rate Unbundling – Performed rate unbundling of retail rates of Orange & Rockland Utilities, Inc. to facilitate delivery of New York Power Authority energy to customer located in Orange & Rockland's service territory. 1992

Vintage Year Salvage and Study - Managed joint study of staff from Rochester Gas and Electric Corporation and NYSPSC to determine feasibility of using vintage year salvage accounting for determining future salvage rates. 1985

Environmental Issues

Energy Conservation Study – **Pascoag Utility District – Designed energy conservation rebate program based on cost benefit study of various alternatives. Program funded through State mandated collection of energy conservation monies from ratepayers. 2002**

Clean Air Act Lawsuit – New York State Attorney General – Investigated modifications made at coal fired generating units of New York utilities to determine whether major modifications were made with obtaining pre-construction permits as required by the prevention of Significant Deterioration (PSD) provisions of the Act. 1999-2002.

Environmental Impact Study and Simulation Modeling Analysis – Analyzed potential environmental impacts of restructuring electric industry in NY using production simulation model PROMOD. 1996

Renewable Resources – Project Leader in NYSPSC proceeding regarding development and implementation of utility plans to promote use of renewable resources. 1995

Environmental and Economic Impacts Study – Directed study of pool-wide power plant dispatch with environmental adders to determine environmental and economic effects of dispatching electric power plants with monetized environmental adders. 1994

Clean Air Impact Study – Directed study of effects of the Clean Air Act of 1990. Measured statewide cost savings if catalytic reduction control facilities were elected to comply with 1990 Clean Air Act Amendments; installed components on units in metropolitan NY region. 1994

Environmental Externalities and Socioeconomic Impacts Study – Managed NYSPSC proceeding to determine whether to incorporate environmental costs into Long-Run Avoided Costs for the State's electric utilities. Study purposes: explore the socioeconomic impacts of electric production as compared with DSM; monetize environmental impacts of electricity. 1993

EXPERT WITNESS TESTIMONY

Case 08-E-0539 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by $854 million. 2008

Docket No. 08-07-04 - United Illuminating - On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's proposed construction budget. 2008

Docket No. 08-06036 – Spring Creek Utilities - On behalf of the Nevada Attorney General's Bureau of Consumer Protection testified on the overall revenue requirement, the cost allocation and amortization of a new financial accounting system, the appropriate level of rate case expense, allocation of corporate salaries, recovery of property taxes, and rate design. 2008

D.P.U. 8-35 – New England Gas Company – On behalf of the Massachusetts Attorney General testified to the reasonableness of the Company's request to increase rates in light of the terms of a previous settlement, the level of expenses being charged from the parent Company to the affiliate, the proposed increase in deprecation expense and the proposed revenue allocation and rate design. 2008

Docket No. 08-96 - Artesian Water Company - on behalf of the Staff of the Delaware Public Service Commission examined the reasonableness of the Company's cost of service study and proposed revenue allocation and rate design. 2008

Docket No. E-01345A-08-0172 - Arizona Public Service - on behalf of the on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposal regarding demand side management cost recovery. 2009

Docket No. 05-03-17PH02 – Southern Connecticut Gas Company – on behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's embedded costs of service study and proposed revenue allocation and rate design. 2008

Docket No. 06-03-04PH02 – Connecticut Natural Gas Corporation – on behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's embedded cost of service study and proposed revenue allocation and rate design. 2008

Docket No. G-01551A-07-0504 – Southwest Gas Corporation – on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposals regarding revenue decoupling. 2008

Docket No. E-01933A-07-0402 – Tucson Electric Power Company – on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposals regarding mandatory time of use rates. 2008

Docket No. 07-09030 – Southwest Gas Corporation – on behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates. 2008

Civil Action 05-C-457-1 – Dominion Hope – on behalf of former employee of the utility examined the utility's hedging and sales for resale practices between affiliates. 2008

Case 07-829-GA-AIR – Dominion East Ohio – on behalf of the Office of the Ohio Consumer's Counsel examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation and rate design and examined the reasonableness of proposals on revenue decoupling and straight fixed variable rate design. 2008

Case 07-S-1315 – Consolidated Edison Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2008

Case No. 9134 – Green Ridge Utilities, Inc. – on behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed rate application including the appropriate cost allocation and amortization period for expenses incurred to develop and implement Project Phoenix (a new software and financial accounting system project), the appropriate level of rate case expense, the requested rate of return and the appropriate level and allocation for common expenses from the parent company. 2008

Case No. 9135 -- Provinces Utilities, Inc. – on behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed rate application including the appropriate cost allocation and amortization period for expenses incurred to develop and implement Project Phoenix (a new software and financial accounting system project), the appropriate level of rate case expense, the requested rate of return and the appropriate level and allocation for common expenses from the parent company. 2008

Case 07-M-0906 – Energy East and Iberdola – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the proposed Acquisition of Energy East Corporation by Iberdrola merger. 2008

Case 07-E-0523 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by over $1.2 billion or 33%. 2007

Docket Nos. ER07-459-002, ER07-513-002, and EL07-11-002 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville on whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission 2007

Docket No. 07-05-19 – Aquarion Water Company – On behalf of the Connecticut Office of Peoples Counsel examined the reasonableness of the utility's proposed revenue allocation, rate design, weather normalization and depreciation rates 2007

Docket No. E-04204A-06-0783 – UNS Electric – On behalf of the Arizona Corporation Commission testified on the reasonableness of the utility's proposed revenue allocation and rate design. 2007

Docket Nos. 06-11022 and 06-11023 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2007

Case 06-G-1186 – KeySpan Delivery Long Island – on behalf of the Counties of Nassau and Suffolk analyzed the Company's proposed rate design and its for amortization of costs for expenditures relating to Manufactured Gas Plants. 2007

Case 06-M-0878 – National Grid and KeySpan Corporation -- on behalf of the Counties of Nassau and Suffolk analyzed the public benefit of the proposed merger, customer service, demand side management programs, rate relief as it relates to competition and customer choice, the repowering of the existing generating stations on Long Island, and the remediation of contamination caused by Manufactured Gas Plants. 2007

Docket No. 06-07-08 – Connecticut Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, revenue allocation and rate design. 2006

Docket No. EL07-11-000 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville evaluated whether the proposed and subsequently abandoned allocation of costs for the Lamoille County Project was reasonable and whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission.

2006

Case 05-S-1376 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2006

Docket No. 06-48-000 – Braintree Electric Light Department – On behalf of the municipal utility presented an cost of service study used to calculate the annual revenue requirement for a generating station that was deemed to be required for reliability purposes. 2006

Case 05-E-1222 – New York State Electric and Gas Corporation – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed average service lives, forecast net salvage figures, and proposal to switch from whole life to remaining life method. 2006

Docket No. 05-10004 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed electric depreciation rates and expense levels. 2006

Docket No. 05-10006 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed gas depreciation rates and expense levels. 2006

Docket No. ER06-17-000 – ISO New England, Inc. – On behalf of a group of municipal utilities in Massachusetts prepared an affidavit on the reasonableness of proposed changes to the Regional Network Service transmission revenue requirements rate setting formula. 2005

Case 04-E-0572 – Consolidated Edison – Electric Rate – On behalf of the County of Westchester testified to the reasonableness of the Company's revenue allocation amongst service classes and the company's fully allocated embedded cost of service study. 2004

Docket No. 04-02-14 – Aquarion Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, weather normalization proposal and certain operation and maintenance expense forecasts. 2004

Docket No. U-13691 – Detroit Thermal, LLC – On behalf of the Henry Ford Health Systems testified on the reasonableness of the utility's proposed default tariffs for steam service. 2004

Docket No. 04-3011 – Southwest Gas Corporation – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Docket No. ER03-563-030 -- Devon Power, LLC, *et al.* – On behalf of the Wellesley Municipal Light Plant filed a prepared affidavit with FERC with respect the proposal of ISO New England, Inc. to establish a locational Installed Capability market in New England. 2004

Docket No. 03-10002 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Case 03-E-0765 – Rochester Gas and Electric Corporation - Before the New York Public Service Commission submitted testimony on rate design, rate unbundling, depreciation, commodity supply and reasonableness and ratemaking treatment of proceeds from the sale of a nuclear generating plant. 2003

New York State Department of Taxation and Finance Versus Brooklyn Navy Yard Cogeneration Partners – Testified on behalf of independent power producer in income tax case regarding tax payments associated with gas used to produce electricity. Testimony focused on ratemaking policies and practices in New York State. 2003

Docket No. 2930 – Narragansett Electric – Before the Rhode Island Public Utilities Commission submitted testimony on the reasonableness of the utility's proposed shared savings filing and its implications for the overall reasonableness of the Company's distribution rates. 2003

Docket No. 03-07-01 – Connecticut Light and Power Company – Before the Connecticut Department of Public Utility Control testified to the recovery of "federally mandated" wholesale power costs. 2003

Docket No. ER03-1274-000 – Boston Edison Company – Before the Federal Energy Regulatory Commission submitted affidavit on the reasonableness of the utility's proposed depreciation rates and expense levels. 2003

Case 210293 – Corning Incorporated – Before the New York Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 332311 – Nucor Steel Auburn, Inc. – Before the New York State Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 6455/03 – Prepared affidavit for consideration by the Supreme Court of the State of New York as to the purpose, need and fuel choice for the Jamaica Bay Energy Center (Jamaica Bay) as it related to good utility planning practice for meeting the energy needs of utility customers. 2003

Case 00-M-0504 – New York State Electric and Gas Corporation – Reviewed reasonableness of utility's fully allocated embedded cost of service study and proposed unbundled delivery rates. 2002

Docket No. TX96-4-001 – On behalf of the Suffolk County Electrical Agency proposed unbundled embedded cost rates for wheeling of wholesale power across distribution facilities. 2002

Case 00-E-1208 – Consolidated Edison: Electric Rate Restructuring – On behalf of Westchester County, addressed reasonableness of having differentiated delivery services rates for New York City and Westchester. 2001

Case 01-E-0359 – Petition of New York State Electric & Gas – Multi-Year Electric Price Protection Plan – Addressed reasonableness of Price Protection Plan (PPP); presented alternative rate plan that called for 20% decrease in utility's base rates. 2001

Case 01-E-0011 – Joint Petition of Co-Owners of Nine Mile Nuclear Station – Addressed the reasonableness of the proposed nuclear asset sale and the ratemaking treatment of the after gain sale proposed by NYSEG. 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of ISO's proposed $4.75/kW/month Installed Capability Deficiency Charge. June 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of proposed $0.17/kW/month Installed Capability Deficiency Charge. January 2001

Docket No. 2861 – Pascoag Fire District: Standard Offer, Charge, Transition Charge and Transmission Charge – Testified on elements of individual charges, procedures for calculation and reasons for changes from previous filed rates. 2001

Case 96-E-0891 – New York State Electric & Gas: Retail Access Credit Phase – On behalf of a large industrial customer, testified on cost of service considerations regarding NYSEG's earnings performance under the terms of a multi-year rate plan and the appropriate level of Retail Access Credit for customers seeking alternate service from alternate suppliers. 2000

Docket No. ER99-978-000 – Boston Edison Company: Open Access Transmission Tariff – Testified on design, revenue requirement, and reasonableness of proposed formula rates proposed by Boston Edison Company for calculating charges for local network transmission service under open access tariff. 1999

Docket Nos. OA97-237-000, et. al. – New England Power Pool: OATT – Testified on design, revenue requirement, and reasonableness of proposed formula rate for transmission service; testified to proposed rates, charges, terms and conditions for ancillary services. 1999

Docket No. 2688 – Pascoag Fire District: Electric Rates – Testified on elements of savings resulting from renegotiation of contract with wholesale power supplier and presented analysis that justified need for and amount of base rate increase. 1998

New York State Department of Taxation and Finance Versus Zapco Energy Tactics Corporation – Testified on behalf of independent power producer in income tax case regarding tax payments associated with electric interconnection equipment. Testimony focused on policies and practices faced in doing business in New York State. 1998

Docket No. 2516 – Pascoag Fire District: Utility Restructuring – Testified on manner and means for utility's restructuring in compliance with Rhode Island Utility Restructuring Act of 1996. Testimony presented a methodology for calculating stranded cost charge, unbundled rates, and new terms and conditions of electric services in deregulated environment. 1997

Case 94-E-0334 – Consolidated Edison: Electric Rates – Led Staff team in review of utility's multi-year rate filing seeking increased rates of $400 million. Directed team in review of resource planning, power purchase contract administration, and fuel and purchased power expenses and testified on reasonableness of company's actions regarding buy-out of contract with an independent power producer and renegotiation of contract with another independent power producer. Lead negotiations for multi-year settlement and performance-based ratemaking package that resulted in a three-year rate freeze. 1994

Case 93-G-0996 – Consolidated Edison: Gas Rates – Testified on reasonableness of utility's proposed depreciation rates. 1994

Case 93-S-0997 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's resource planning for steam utility system. 1994

Case 93-S-0997 and 93-G-0996 – Consolidated Edison: Steam Rates – Testified on reasonableness of multi-year rate plan proposed by the utility. 1994

Case 94-E-0098 – Niagara Mohawk: Electric Rates – Reviewed utility's management of its portfolio of power purchase contracts with independent power producers for the reasonableness of recovery of costs in retail rates. 1994

Case 93-E-0807 – Consolidated Edison: Electric Rates – Testified on rate recovery mechanism for costs associated with termination of five contracts with independent power producers. 1993

Case 92-E-0814 – Petition for Approval of Curtailment Procedures – Testified on methodology for estimating amount of power required to be curtailed and staff's estimate of curtailment. 1992

Case 90-S-0938 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's embedded cost of service study, and proposed revenue re-allocation and rate design. 1991

Case 91-E-0462 – Consolidated Edison: Electric Rates – Implementation of partial pass-through fuel adjustment incentive clause. 1991

Case 90-E-0647 – Rochester Gas and Electric: Electric Rates – Analysis and estimation of monthly fuel and purchased power costs for use in utility's performance based partial pass-through fuel adjustment clause. 1990

Case 29433 – Central Hudson Gas and Electric: Electric Rates – Analysis of utility's construction budgeting process, rate year electric plant in service forecast, lease revenue forecast, forecast and rate treatment of profits from sales of wholesale power and estimation of fuel and purchased power expenses for use in the utility's partial pass-through fuel adjustment clause. 1987

Case 29674 – Rochester Gas and Electric: Electric Rates – Review of utility's historic and forecast O&M expenditure levels forecast and rate treatment of profits from wholesale power, and estimation of fuel and purchased power expenses, and price out of incremental revenues from increased retail sales. 1987

Case 29195 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process, analysis of rate year electric plant in service, forecast and rate treatment of profits from sales of wholesale power, and estimation of fuel and purchased power expenses. 1986

Case 29046 – Orange and Rockland Utilities: Electric Rates – Testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 1985

Case 28313 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process; analysis of rate year electric plant in service forecast; review of rate year operations and maintenance expense forecast; forecast and rate treatment of profits from sales of wholesale power; estimation of fuel and purchased power expenses. 1984

Case 28316 – Rochester Gas and Electric: Steam Rates – Price out of steam sales including the review of historic sales growth, usage patterns and forecast number of customers. 1984

PRESENTATIONS

National Association of State Utility Consumer Advocates Annual Conference, 2008 – Speaker on a case study of "Smart Metering"

Multiple Intervenors Annual Conference – What Will Impact Market Prices? 1998, Syracuse, New York – Speaker on the impact that deregulation would have on market prices for large industrial customers.

IBC Conference – Successful Strategies for Negotiating Purchased Power Contracts, 1997, Washington, DC – Speaker on NY power purchase contract policies, ratepayer valuation, contract approval process and policy on recovery of buyout costs.

Gas Daily Conference – Fueling the Future: Gas' Role in Private Power Projects, 1992, Houston, Texas – Panel member addressing changing power supply requirements of electric utilities.

MEMBERSHIPS/ASSOCIATIONS

Member Municipal Electric Utility Association, Northeast Public Power Association and New York State ISO.

Exhibit 2
RUCO Proof of Revenues

Line No.	Class of Service	Billed BD (for Jul 2007 - Nov 2007	Billed BD (for Dec 2007 - Jun 2008	Total TY Unadjusted Billing Units	Rates as of Jul 2007 - Nov 2007	Existing Rates as of Dec 1, 2007	Current Unadjusted Billed Revenues	Allocation of Booked to Billed Revenue Difference	Unadjusted Revenues
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	H
				(A + B)			(A*D + B*E)	(F / Col. H, L.50)*Col. H, L.49	(F + G)
	Residential Service (R10)								
1	Customer Charge	625,116	882,107	1,507,223	$7.00	$8.50	$11,873,722		
2	Distribution Margin Therms	13,683,976	57,039,061	70,723,037	$0.3004	$0.3270	$22,762,439		
3	**TOTAL R10**						$34,636,161	$231,128	$34,867,289
	Residential Service Cares (R12)								
4	Customer Charge	32,616	48,322	80,938	$7.00	$7.00	$566,566		
5	Distribution Margin Therms - Summer	421,429	246,155	667,584	$0.3004	$0.3270	$207,090		
6	Distribution Margin Therms - Winter Non Discou	34,578	358,932	393,511	$0.3004	$0.3270	$127,758		
7	Distribution Margin Therms - Winter Discount	212,411	2,204,870	2,417,281	$0.1504	$0.1770	$422,209		
	TOTAL R12						$1,323,623	$8,833	$1,332,455
	Small Volume Commercial Service (C20)								
8	Customer Charge	56,440	80,641	137,081	$11.00	$13.50	$1,709,494		
9	Distribution Margin Therms	8,070,305	22,048,952	30,119,256	$0.2420	$0.2638	$7,769,527		
10	**TOTAL R20**						$9,479,021	$63,254	$9,542,274
	Large Volume Commercial Service (C22)								
11	Customer Charge	83	99	182	$85.00	$100.00	$16,955		
12	Distribution Margin Therms	473,791	968,787	1,442,578	$0.1551	$0.1718	$239,923		
13	**TOTAL R22**						$256,878	$1,714	$258,592
	Large Volume Commercial Transportation Service (C22)								
14	Customer Charge	65	60	125	$85.00	$100.00	$11,525		
15	Distribution Margin Therms	1,613,646	1,730,988	3,344,634	$0.1551	$0.1718	$547,660		
16	**TOTAL R22**						$559,185	$3,731	$562,917
	Small Volume Industrial Service (I-30)								
17	Customer Charge	76	136	212	$11.00	$13.50	$2,672		
18	Distribution Margin Therms	111,336	391,243	502,579	$0.2122	$0.2356	$115,802		
19	**TOTAL I30**						$118,474	$791	$119,265
	Large Volume Industrial Service (I-32)								
20	Customer Charge	31	37	68	$85.00	$100.00	$6,335		
21	Distribution Margin Therms	460,636	785,611	1,246,247	$0.0864	$0.0952	$114,589		
22	**TOTAL I32**						$120,924	$807	$121,731
	Large Volume Industrial Transportation Service (I-32)								
23	Customer Charge	50	91	141	$85.00	$100.00	$13,350		
24	Distribution Margin Therms	4,420,876	7,022,697	11,443,573	$0.0864	$0.0952	$1,050,524		
25	**TOTAL I32**						$1,063,874	$7,099	$1,070,974

Line No.	Class of Service	Billed BD (for Jul 2007 - Nov 2007	Billed BD (for Dec 2007 - Jun 2008	Total TY Unadjusted Billing Units	Rates as of Jul 2007 - Nov 2007	Existing Rates as of Dec 1, 2007	Current Unadjusted Billed Revenues	Allocation of Booked to Billed Revenue Difference	Unadjusted Revenues
	Small Volume Public Authority (PA-40)								
26	Customer Charge	5,288	7,459	12,747	$11.00	$13.50	$158,865		
27	Customer Charge - CNG	35	47	82	$30.00	$30.00	$2,460		
28	Distribution Margin Therms	960,064	4,837,614	5,797,679	$0.2351	$0.2593	$1,480,105		
29	**TOTAL PA40**						$1,641,429	$10,953	$1,652,382
	Large Volume Public Authority (PA-42)								
30	Customer Charge	25	35	60	$85.00	$100.00	$5,625		
31	Distribution Margin Therms	319,860	905,213	1,225,072	$0.1084	$0.1198	$143,117		
32	**TOTAL PA42**						$148,742	$993	$149,735
	Large Volume Public Authority Transportation Service (PA-42)								
33	Customer Charge	30	56	86	$85.00	$100.00	$8,150		
34	Distribution Margin Therms	1,309,069	3,818,141	5,127,210	$0.1084	$0.1198	$599,316		
35	**TOTAL PA42**						$607,466	$4,054	$611,520
	Special Gas Light Service (PA-44)								
36	Customer Charge Lighting Group A	45	63	108	$13.57	$15.17	$1,566		
37	Customer Charge Lighting Group B	1,495	2,093	3,588	$16.28	$18.20	$62,431		
38	**TOTAL PA44**	53,421	91,985	145,406			$63,998	$427	$64,425
	Irrigation Service (IR-60)								
39	Customer Charge	25	35	60	$11.00	$13.50	$748		
40	Distribution Margin Therms	88,197	16,069	104,267	$0.2876	$0.3192	$30,495		
41	**TOTAL IR60**						$31,242	$208	$31,451
	T1 Contract Customers								
42	Customer Charge	15	21	36	$85.00	$100.00	$3,375		
43	Distribution Margin Therms	1,668,664	5,895,627	7,564,291	$0.0867	$0.0867	$655,582		
44	**TOTAL IR60**						$658,957	$0	$658,957
	T2 - Customer								
45	Customer Charge	5	7	12	$85.00	$100.00	$1,125		
46	Distribution Margin Therms	311,964	839,169	1,151,133	$0.0544	$0.0544	$62,652		
47	**TOTAL IR60**						$63,777	$0	$63,777
48	**Customers**	**719,910**	**1,019,167**	**1,739,077**					
49	**Therms**	**34,214,222**	**109,201,115**	**143,415,337**					
50	**Revenue**						**$50,773,751**	**$333,992**	**$51,107,743**
50						Revenue Requirement Model	**$51,107,743**		
51						Difference	($333,992)		
52							**$333,992**		

Valencia is charge a monthly Reservation Charge of $4,472.77
Rate per Therm of .0078

$50,051,018

Line No.	Class of Service	Total TY Unadjusted Billing Units	Existing Rates as of Dec 1, 2007	Unadjusted Revenues	Revenue Annualization	Revenue Annualization Adjustment
	Residential Service (R10)					
1	Customer Charge	1,507,223	$8.50		$12,811,396	
2	Distribution Margin Therms	70,723,037	$0.3270		$23,126,433	
3	**TOTAL R10**			$34,867,289	$35,937,829	$1,070,540
	Residential Service Cares (R12)					
4	Customer Charge	80,938	$7.00		$566,566	
5	Distribution Margin Therms - Summer	667,584	$0.3270		$218,300	
6	Distribution Margin Therms - Winter	393,511	$0.3270		$128,678	
7	Distribution Margin Therms - Winter	2,417,281	$0.1770		$427,859	
	TOTAL R12			$1,332,455	$1,341,403	$8,947
	Small Volume Commercial Service (C20)					
8	Customer Charge	137,081	$13.50		$1,850,594	
9	Distribution Margin Therms	30,119,256	$0.2638		$7,945,460	
10	**TOTAL R20**			$9,542,274	$9,796,053	$253,779
	Large Volume Commercial Service (C22)					
11	Customer Charge	182	$100.00		$18,200	
12	Distribution Margin Therms	1,442,578	$0.1718		$247,835	
13	**TOTAL R22**			$258,592	$266,035	$7,443
	Large Volume Commercial Transportation Service					
14	Customer Charge	125	$100.00		$12,500	
15	Distribution Margin Therms	3,344,634	$0.1718		$574,608	
16	**TOTAL R22**			$562,917	$587,108	$24,191
	Small Volume Industrial Service (I-30)					
16	Customer Charge	212	$13.50		$2,862	
17	Distribution Margin Therms	502,579	$0.2356		$118,408	
18	**TOTAL I30**			$119,265	$121,270	$2,005
	Large Volume Industrial Service (I-32)					
19	Customer Charge	68	$100.00		$6,800	
20	Distribution Margin Therms	1,246,247	$0.0952		$118,643	
21	**TOTAL I32**			$121,731	$125,443	$3,712
	Large Volume Industrial Transportation Service					
22	Customer Charge	141	$100.00		$14,100	
23	Distribution Margin Therms	11,443,573	$0.0952		$1,089,428	
24	**TOTAL I32**			$1,070,974	$1,103,528	$32,554
	Small Volume Public Authority (PA-40)					
25	Customer Charge	12,747	$13.50		$172,085	
26	Customer Charge - CNG	82	$30.00		$2,460	
27	Distribution Margin Therms	5,797,679	$0.2593		$1,503,338	
28	**TOTAL PA40**			$1,652,382	$1,677,883	$25,500
	Large Volume Public Authority (PA-42)					
29	Customer Charge	60	$100.00		$6,000	
30	Distribution Margin Therms	1,225,072	$0.1198		$146,764	
31	**TOTAL PA42**			$149,735	$152,764	$3,029

Line No.	Class of Service	Total TY Unadjusted Billing Units	Existing Rates as of Dec 1, 2007	Unadjusted Revenues	Revenue Annualization	Revenue Annualization Adjustment
	Large Volume Public Authority Transportation Service					
32	Customer Charge	86	$100.00		$8,600	
33	Distribution Margin Therms	5,127,210	$0.1198		$614,240	
34	**TOTAL PA42**			$611,520	$622,840	$11,320
	Special Gas Light Service (PA-44)					
35	Customer Charge Lighting Group A	108	$15.17		$1,638	
36	Customer Charge Lighting Group B	3,588	$18.20		$65,302	
37	**TOTAL PA44**	145,406		$64,425	$66,940	$2,515
	Irrigation Service (IR-60)					
38	Customer Charge	60	$13.50		$810	
39	Distribution Margin Therms	104,267	$0.3192		$33,282	
40	**TOTAL IR60**			$31,451	$34,092	$2,641
	T1 Contract Customers					
41	Customer Charge	36	$100.00		$3,600	
42	Distribution Margin Therms	7,564,291	$0.0867		$655,582	
43	**TOTAL IR60**			$658,957	$659,182	$225
	T2 - Customer					
44	Customer Charge	12	$100.00		$1,200	
45	Distribution Margin Therms	1,151,133	$0.0544		$62,652	
46	**TOTAL IR60**			$63,777	$63,852	$75
47	**Customers**	**1,739,077**				
48	**Therms**	**140,998,057**				
49	**Revenue**			**$51,107,743**	**$52,556,220**	**$1,448,476**

Line No.	Class of Service	Total TY Unadjusted Billing Units	Existing Rates as of Dec 1, 2007	Unadjusted Revenues	Revenue Annualization	Revenue Annualization Adjustment	UNSG Adj. for Customer Annualizaton	UNSG Adj. for Weather Normalization	Adjusted Billing units	TY Adjusted Revenues	Total Customer & Weather Revenue Adjustment
	Residential Service (R10)										
1	Customer Charge	1,507,223	$8.50		$12,811,396		0		1,507,223	$12,811,396	
2	Distribution Margin Therms	70,723,037	$0.3270		$23,126,433		0	(1,993,041)	68,729,996	$22,474,709	
3	TOTAL R10			$34,867,289	$35,937,829	$1,070,540				$35,286,104	$651,725
	Residential Service Cares (R12)										
4	Customer Charge	80,938	$7.00		$566,566		0		80,938	$566,566	
5	Distribution Margin Therms - Summer	667,584	$0.3270		$218,300		0	(52,587)	614,997	$201,104	
6	Distribution Margin Therms - Winter	393,511	$0.3270		$128,678		0	(6,624)	386,887	$126,512	
7	Distribution Margin Therms - Winter	2,417,281	$0.1770		$427,859		0	(40,688)	2,376,593	$420,657	
	TOTAL R12			$1,332,455	$1,341,403	$8,947			3,378,478	$1,314,839	$26,564
	Small Volume Commercial Service (C20)										
8	Customer Charge	137,081	$13.50		$1,850,594		0		137,081	$1,850,594	
9	Distribution Margin Therms	30,119,256	$0.2638		$7,945,460		0	(557,223)	29,562,033	$7,798,464	
10	TOTAL R20			$9,542,274	$9,796,053	$253,779				$9,649,058	$146,996
	Large Volume Commercial Service (C22)										
11	Customer Charge	182	$100.00		$18,200		0		182	$18,200	
12	Distribution Margin Therms	1,442,578	$0.1718		$247,835		0	(25,686)	1,416,892	$243,422	
13	TOTAL R22			$258,592	$266,035	$7,443				$261,622	$4,413
	Large Volume Commercial Transportation Service (C22)										
14	Customer Charge	125	$100.00		$12,500		0		125	$12,500	
15	Distribution Margin Therms	3,344,634	$0.1718		$574,608		0	0	3,344,634	$574,608	
16	TOTAL R22			$562,917	$587,108	$24,191				$587,108	$0
	Small Volume Industrial Service (I-30)										
16	Customer Charge	212	$13.50		$2,862		0		212	$2,862	
17	Distribution Margin Therms	502,579	$0.2356		$118,408		0	0	502,579	$118,408	
18	TOTAL I30			$119,265	$121,270	$2,005				$121,270	$0
	Large Volume Industrial Service (I-32)										
19	Customer Charge	68	$100.00		$6,800		0		68	$6,800	
20	Distribution Margin Therms	1,246,247	$0.0952		$118,643		0	0	1,246,247	$118,643	
21	TOTAL I32			$121,731	$125,443	$3,712				$125,443	$0
	Large Volume Industrial Transportation Service (I-32)										
22	Customer Charge	141	$100.00		$14,100		0		141	$14,100	
23	Distribution Margin Therms	11,443,573	$0.0952		$1,089,428		0	0	11,443,573	$1,089,428	
24	TOTAL I32			$1,070,974	$1,103,528	$32,554				$1,103,528	$0
	Small Volume Public Authority (PA-40)										
25	Customer Charge	12,747	$13.50		$172,085		0		12,747	$172,085	
26	Customer Charge - CNG	82	$30.00		$2,460		0		82	$2,460	
27	Distribution Margin Therms	5,797,679	$0.2593		$1,503,338		0	(187,359)	5,610,320	$1,454,756	
28	TOTAL PA40			$1,652,382	$1,677,883	$25,500				$1,629,301	$48,582
	Large Volume Public Authority (PA-42)										
29	Customer Charge	60	$100.00		$6,000		0		60	$6,000	
30	Distribution Margin Therms	1,225,072	$0.1198		$146,764		0	(32,942)	1,192,130	$142,817	
31	TOTAL PA42			$149,735	$152,764	$3,029				$148,817	$3,947
	Large Volume Public Authority Transportation Service (PA-42)										
32	Customer Charge	86	$100.00		$8,600		0		86	$8,600	
33	Distribution Margin Therms	5,127,210	$0.1198		$614,240		0	0	5,127,210	$614,240	

Line No.	Class of Service	Total TY Unadjusted Billing Units	Existing Rates as of Dec 1, 2007	Unadjusted Revenues	Revenue Annualization	Revenue Annualization Adjustment	UNSG Adj. for Customer Annualizaton	UNSG Adj. for Weather Normalization	Adjusted Billing units	TY Adjusted Revenues	Total Customer & Weather Revenue Adjustment
34	TOTAL PA42			$611,520	$622,840	$11,320				$622,840	$0
	Special Gas Light Service (PA-44)										
35	Customer Charge Lighting Group A	108	$15.17		$1,638		0		108	$1,638	
36	Customer Charge Lighting Group B	3,588	$18.20		$65,302		0	0	3,588	$65,302	
37	TOTAL PA44	145,406		$64,425	$66,940	$2,515			145,406	$66,940	$0
	Irrigation Service (IR-60)										
38	Customer Charge	60	$13.50		$810				60	$810	
39	Distribution Margin Therms	104,267	$0.3192		$33,282		0	(712)	103,554	$33,055	
40	TOTAL IR60			$31,451	$34,092	$2,641			0	$33,865	$227
	T1 Contract Customers										
41	Customer Charge	36	$100.00		$3,600		0		36	$3,600	
42	Distribution Margin Therms	7,564,291	$0.0867		$655,582		0	0	7,564,291	$655,582	
43	TOTAL IR60			$658,957	$659,182	$225	-			$659,182	$0
	T2 - Customer										
44	Customer Charge	12	$100.00		$1,200		0		12	$1,200	
45	Distribution Margin Therms	1,151,133	$0.0544		$62,652		0	0	1,151,133	$62,652	
46	TOTAL IR60			$63,777	$63,852	$75				$63,852	$0
47	Customers	1,739,041					-		1,739,041		
48	Therms	133,433,766					-	(2,896,863)	140,518,475		
49	Revenue			$51,107,743	$52,556,220	$1,448,476 #				$51,673,767	$882,453

UNS GAS, INC. PROPOSED RATES AND PROPOSED REVENUES
TEST PERIOD TME JUNE 30, 2008

Line No.	Class of Service	Existing Rates as of Dec 1, 2007	Adjusted Billing units	TY Adjusted Revenues	Proposed Increase	Total Revenue Requirement	New Rates	Total Revenue Requirement	Percentage Increase
								Year 1	
	Residential Service (R10)								
1	Customer Charge	$8.50	1,507,223	$12,811,396			$10.00	$15,072,230	17.65%
2	Distribution Margin Therms	$0.3270	68,729,996	$22,474,709			$0.3027	$20,803,904	
3	**TOTAL R10**			$35,286,104	$590,030	$35,876,134		$35,876,134	1.67%
								$0	
	Residential Service Cares (R12)								
4	Customer Charge	$7.00	80,938	$566,566			$7.00	$566,566	0.00%
5	Distribution *Margin Therms - Summer*	$0.3270	614,997	$201,104			$0.3270	$201,104	
6	Distribution Margin Therms - Winter	$0.3270	386,887	$126,512			$0.3270	$126,512	
7	Distribution Margin Therms - Winter	$0.1770	2,376,593	$420,657			$0.1770	$420,657	
	TOTAL R12			$1,314,839	$0	$1,314,839		$1,314,839	0.00%
	Small Volume Commercial Service (C20)								
8	Customer Charge	$13.50	137,081	$1,850,594			$15.50	$2,124,756	14.81%
9	Distribution Margin Therms	$0.2638	29,562,033	$7,798,464			$0.2600	$7,685,647	
10	**TOTAL R20**			$9,649,058	$161,345	$9,810,403		$9,810,403	1.67%
								$0	
	Large Volume Commercial Service (C22)								
11	Customer Charge	$100.00	182	$18,200			$105.00	$19,110	5.00%
12	Distribution Margin Therms	$0.1718	1,416,892	$243,422			$0.1742	$246,887	
13	**TOTAL R22**			$261,622	$4,375	$265,997		$265,997	1.67%
	Large Volume Commercial Transportation Service (C22)								
14	Customer Charge	$100.00	125	$12,500			$105.00	$13,125	5.00%
15	Distribution Margin Therms	$0.1718	3,344,634	$574,608			$0.1742	$582,787	
16	**TOTAL R22**			$587,108	$9,817	$596,925		$595,912	1.50%
								-$1,014	
	Small Volume Industrial Service (I-30)								
16	Customer Charge	$13.50	212	$2,862			$15.50	$3,286	14.81%
17	Distribution Margin Therms	$0.2356	502,579	$118,408			$0.2388	$120,011	
18	**TOTAL I30**			$121,270	$2,028	$123,297		$123,297	1.67%
								$0	
	***Large Volume* Industrial Service (I-32)**								
19	Customer Charge	$100.00	68	$6,800			$105.00	$7,140	5.00%
20	Distribution Margin Therms	$0.0952	1,246,247	$118,643			$0.0966	$120,400	
21	**TOTAL I32**			$125,443	$2,098	$127,540		$127,540	1.67%
	Large Volume Industrial Transportation Service (I-32)								
22	Customer Charge	$100.00	141	$14,100			$105.00	$14,805	5.00%
23	Distribution Margin Therms	$0.0952	11,443,573	$1,089,428			$0.0968	$1,107,176	
24	**TOTAL I32**			$1,103,528	$18,452	$1,121,981		$1,121,981	1.67%
								$0	
	Small Volume Public Authority (PA-40)								
25	Customer Charge	$13.50	12,747	$172,085			$15.50	$197,579	14.81%
26	Customer Charge - CNG	$30.00	82	$2,460			$15.50	$1,271	-48.33%
27	Distribution Margin Therms	$0.2593	5,610,320	$1,454,756			$0.2598	$1,457,695	0.20%
28	**TOTAL PA40**			$1,629,301	$27,244	$1,656,545		$1,656,545	
								$0	
	Large Volume Public Authority (PA-42)								
29	Customer Charge	$100.00	60	$6,000			$105.00	$6,300	
30	Distribution Margin Therms	$0.1198	1,192,130	$142,817			$0.1216	$145,006	

UNS GAS, INC. PROPOSED RATES AND PROPOSED REVENUES
TEST PERIOD TME JUNE 30, 2008

Line No.	Class of Service	Existing Rates as of Dec 1, 2007	Adjusted Billing units	TY Adjusted Revenues	Proposed Increase	Total Revenue Requirement	New Rates	Total Revenue Requirement	Percentage Increase
31	**TOTAL PA42**			$148,817	$2,488	$151,306		$151,306	1.67%
								$0	
	Large Volume Public Authority Transportation Service (PA-42)								
32	Customer Charge	$100.00	86	$8,600			$105.00	$9,030	5.00%
33	Distribution Margin Therms	$0.1198	5,127,210	$614,240			$0.1217	$624,224	
34	**TOTAL PA42**			$622,840	$10,415	$633,254		$633,254	1.67%
								$0	
	Special Gas Light Service (PA-44)								
35	Customer Charge Lighting Group A	$15.17	108	$1,638			$18.41	$1,989	21.39%
36	Customer Charge Lighting Group B	$18.20	3,588	$65,302			$18.41	$66,071	1.18%
37	**TOTAL PA44**		145,406	$66,940	$1,119	$68,059		$68,059	1.67%
								$0	
	Irrigation Service (IR-60)								
38	Customer Charge	$13.50	60	$810			$15.50	$930	14.81%
39	Distribution Margin Therms	$0.3192	103,554	$33,055			$0.3235	$33,501	
40	**TOTAL IR60**		0	$33,865	$566	$34,431		$34,431	1.67%
								$0	
	T1 Contract Customers								
41	Customer Charge	$100.00	36	$3,600			$105.00	$3,780	5.00%
42	Distribution Margin Therms	$0.0867	7,564,291	$655,582			$0.0881	$666,424	
43	**TOTAL IR60**			$659,182	$11,022	$670,204		$670,204	1.67%
								$0	
	T2 - Contract Customer								
44	Customer Charge	$100.00	12	$1,200			$105.00	$1,260	5.00%
45	Distribution Margin Therms	$0.0544	1,151,133	$62,652			$0.0553	$63,659	
46	**TOTAL IR60**			$63,852	$1,068	$64,919		$64,919	1.67%
								$0	
						0			
47	**Customers**		1,739,041						
48	**Therms**		140,518,475						
49	**Revenue**			**$51,673,767**	**$841,000**	**$52,515,835**		**$52,514,821**	1.63%

Exhibit 3
Schedule H – Bill Impacts

UNS Gas, Inc.
Summary of Revenues by Customer Classifications
Adjusted Present Rates And Proposed Rates
Test Year Ended June 30, 2008
(Thousands of Dollars)

Line No.	Class of Service	Adjusted Present Net Revenue	Proposed Net Revenue	Proposed Net Increase	Proposed Percent Increase (a)	Line No.
1	Residential Service	$36,600,943	$37,190,974	$590,030	1.61%	1
2	Commercial Gas Service	9,910,680	10,076,399	165,720	1.67%	2
3	Industrial Gas Service	246,712	250,838	4,125	1.67%	3
4	Public Authority Gas Service	1,778,118	1,807,850	29,732	1.67%	4
5	Special Gas Light Service	66,940	68,059	1,119	1.67%	5
6	Irrigation Service	33,865	34,431	566	1.67%	6
7	Transportation Customers	3,036,509	3,086,270	49,761	1.64%	7
8	Subtotal	51,673,767	52,514,821	841,054	1.63%	8
9	Other Operating Revenue	1,744,743	1,744,743	0	0.00%	9
10	Total	$53,418,510	$54,259,564	$841,054	1.57%	10

Supporting Schedules
(a) H-2 (P2)

Recap Schedules
A-1

UNS Gas, Inc.
Comparisons of Revenues by Rate Schedules
Present And Proposed Rates
Test Year Ended June 30, 2008

Line No.	Class of Service	Rate Schedule Present	Proposed	Actual Therm Sales	Actual Average Number of Customers	Actual Average Therm per Customer	Test Year End Adjustments	Adjusted Therm Sales	Adjusted Average Number of Customers	Adjusted Average Therm per Customer	Line No.
1	Residential Service	R-10	R-10	70,723,037	125,602	563	(2,656,075)	68,066,962	125,602	542	1
2	Residential Service Cares	R-12	R-12	3,478,376	6,745	516	55,060	3,533,436	6,745	524	2
3	Small Volume Commercial Service	C-20	C-20	30,119,256	11,423	2,637	(827,599)	29,291,657	11,423	2,564	3
4	Large Volume Commercial Service	C-22	C-22	1,442,578	15	95,115	(104,334)	1,338,244	15	88,236	4
5	Commercial Transportation	C-22T1	C-22T1	3,344,634	10	321,085	(303,749)	3,040,885	10	291,925	5
6	Small Volume Industrial Service	I-30	I-30	502,579	18	28,448	51,187	553,766	18	31,345	6
7	Large Volume Industrial Service	I-32	I-32	1,246,247	6	219,926	(33,594)	1,212,653	6	213,998	7
8	Industrial Transportation	I-32 T1	I-32 T1	11,443,573	12	973,921	138,953	11,582,526	12	985,747	8
9	Industrial Transportation - Contracts	I-32 T1C	I-32 T1C	7,564,291	3	2,521,430	(2,396,706)	5,167,584	3	1,722,528	9
10	T2 Transportation	I-32 T2	I-32 T2	1,151,133	1	1,151,133	0	1,151,133	1	1,151,133	10
11	Small Volume Public Authority	P-40	P-40	5,797,679	1,069	5,423	(185,370)	5,612,308	1,069	5,250	11
12	Large Volume Public Authority	P-42	P-42	1,225,072	5	245,014	(32,942)	1,192,130	5	238,426	12
13	Public Authority Transportation	P-42T1	P-42T1	5,127,210	7	715,425	270,621	5,397,831	7	753,186	13
14	Special Gas Light Service	P-44	P-44	145,406	2	72,703	0	145,406	2	72,703	14
15	Irrigation Service	I-60	I-60	104,267	5	20,853	(712)	103,554	5	20,711	15
16	Total Gas Service			143,415,337	144,923	990	(6,025,261)	137,390,076	144,923	948	16

Note: Some transportation customers have more than one meter which is accounted for in this schedule.

UNS Gas, Inc.
Comparisons of Revenues by Rate Schedules
Present And Proposed Rates
Test Year Ended June 30, 2008

Line No.	Class of Service	Actual Net Revenue	Test Year End Adjustments	Adjusted Net Revenue	Proposed Increase $	Proposed Increase %	Proposed Net Revenue	Line No.
1	Residential Service	$35,937,829	($651,725)	$35,286,104	$590,030	1.67%	$35,876,134	1
2	Residential Service Cares	1,341,403	($26,564)	1,314,839	0	0.00%	$1,314,839	2
3	Small Volume Commercial Service	9,796,053	($146,996)	9,649,058	161,345	1.67%	$9,810,403	3
4	Large Volume Commercial Service	266,035	($4,413)	261,622	4,375	1.67%	$265,997	4
5	Commercial Transportation	587,108	$0	587,108	8,803	1.50%	$595,912	5
6	Small Volume Industrial Service	121,270	$0	121,270	2,028	1.67%	$123,297	6
7	Large Volume Industrial Service	125,443	$0	125,443	2,098	1.67%	$127,540	7
8	Industrial Transportation	1,103,528	$0	1,103,528	18,452	1.67%	$1,121,981	8
9	Industrial Transportation - Contracts	659,182	$0	659,182	11,022	1.67%	$670,204	9
10	T2 Transportation	63,852	$0	63,852	1,068	1.67%	$64,919	10
11	Small Volume Public Authority	1,677,883	($48,582)	1,629,301	27,244	1.67%	$1,656,545	11
12	Large Volume Public Authority	152,764	($3,947)	148,817	2,488	1.67%	$151,306	12
13	Public Authority Transportation	622,840	$0	622,840	10,415	1.67%	$633,254	13
14	Special Gas Light Service	66,940	$0	66,940	1,119	1.67%	$68,059	14
15	Irrigation Service	34,092	($227)	33,865	566	1.67%	$34,431	15
16	Total Gas Service	$52,556,220	($882,453)	$51,673,767	$841,054	1.63%	$52,514,821	16

UNS Gas, Inc.
Comparison of Present And Proposed Rates
Test Year Ended June 30, 2008

	Present Rate	Proposed Rate	Increase $	Increase %
Residential Service				
Customer Charge	$8.50	$10.00	$1.50	17.65%
Distribution Margin Therms	$0.3270	$0.3027	-$0.0243	-7.43%
Residential Service Cares (R12)				
Customer Charge	$7.00	$7.00	$0.00	0.00%
Distribution Margin Therms Summer	$0.3270	$0.3270	$0.00	0.00%
Distribution Margin Therms Winter (First 100 Therms)	$0.1770	$0.3270	$0.15	84.75%
Distribution Margin Therms Winter all additional therms	$0.3270	$0.1770	-$0.15	-45.87%
Small Commercial Service (C20)				
Customer Charge	$13.50	$15.50	$2.00	14.81%
Distribution Margin Therms	$0.2638	$0.2600	-$0.0038	-1.45%
Large Commercial Service (C22)				
Customer Charge	$100.00	$105.00	$5.00	5.00%
Distribution Margin Therms	$0.1718	$0.1742	$0.0024	1.42%
Small Volume Industrial Service (I-30):				
Customer Charge	$13.50	$15.50	$2.00	14.81%
Distribution Margin Therms	$0.2356	$0.2388	$0.0032	1.35%
Large Volume Industrial Service (I-32):				
Customer Charge	$100.00	$105.00	$5.00	5.00%
Distribution Margin Therms	$0.0952	$0.0966	$0.0014	1.48%
Small Volume PA (PA-40)				
Customer Charge	$13.50	$15.50	$2.00	14.81%
Distribution Margin Therms	$0.2593	$0.2598	$0.0005	0.20%
Large Volume PA (PA-42)				
Customer Charge	$100.00	$105.00	$5.00	5.00%
Distribution Margin Therms	$0.1198	$0.1216	$0.0018	1.53%
Special Gas Light Service (PA-44):				
Single Orifice	$23.72	$18.41	-$5.31	-22.37%
Double Orifice	$39.53	$36.83	-$2.70	-6.83%
Triple Orifice	$54.86	$55.24	$0.38	0.70%
Quadruple Orifice	$71.16	$73.66	$2.50	3.51%
Irrigation Service (IR-60)				
Customer Charge	$13.50	$15.50	$2.00	14.81%
Distribution Margin Therms	$0.3192	$0.3235	$0.0043	1.35%

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended June 30, 2008

Residential Service (R10)		
Customer Charge (Sum: Apr - Nov)	$8.50	$10.00
Distribution Margin Therms	0.3270	0.3027

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
5	$10.14	$11.51	$1.38	13.6%
10	$11.77	$13.03	$1.26	10.7%
20	$15.04	$16.05	$1.01	6.7%
35	$19.95	$20.59	$0.65	3.3%
50	$24.85	$25.13	$0.28	1.1%
75	$33.03	$32.70	($0.32)	-1.0%
100	$41.20	$40.27	($0.93)	-2.3%
250	$90.25	$85.67	($4.58)	-5.1%
500	$172.00	$161.35	($10.65)	-6.2%

Residential Service (R10)		
Customer Charge (Win: Dec-Mar)	$8.50	$10.00
Distribution Margin Therms	0.3270	$0.3027

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
5	$10.14	$11.51	$1.38	13.6%
10	$11.77	$13.03	$1.26	10.7%
20	$15.04	$16.05	$1.01	6.7%
35	$19.95	$20.59	$0.65	3.3%
50	$24.85	$25.13	$0.28	1.1%
75	$33.03	$32.70	($0.32)	-1.0%
100	$41.20	$40.27	($0.93)	-2.3%
250	$90.25	$85.67	($4.58)	-5.1%
500	$172.00	$161.35	($10.65)	-6.2%

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended June 30, 2008

Residential Service Cares (R12)		
Customer Charge (Summer)	$7.00	$7.00
Distribution Margin Therms	0.3270	0.3270

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
5	$8.64	$8.64	$0.00	0.0%
10	$10.27	$10.27	$0.00	0.0%
20	$13.54	$13.54	$0.00	0.0%
35	$18.45	$18.45	$0.00	0.0%
50	$23.35	$23.35	$0.00	0.0%
75	$31.53	$31.53	$0.00	0.0%
100	$39.70	$39.70	$0.00	0.0%
250	$88.75	$88.75	$0.00	0.0%
500	$170.50	$170.50	$0.00	0.0%

Residential Service Cares (R12)		
Customer Charge (Winter)	$7.00	$7.00
Distribution Margin Therms (1st 100 Therms)	0.1770	0.1770
Distribution Margin all additional Therms	0.3270	0.3270

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
5	$7.89	$7.89	$0.00	0.0%
10	$8.77	$8.77	$0.00	0.0%
20	$10.54	$10.54	$0.00	0.0%
35	$13.20	$13.20	$0.00	0.0%
50	$15.85	$15.85	$0.00	0.0%
75	$20.28	$20.28	$0.00	0.0%
100	$24.70	$24.70	$0.00	0.0%
250	$73.75	$73.75	$0.00	0.0%
500	$155.50	$155.50	$0.00	0.0%

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended June 30, 2008

Small Commercial Service (C20)		
Customer Charge	$13.50	$15.50
Distribution Margin Therms	$0.2638	$0.2600

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
50	$26.69	$28.50	$1.81	6.8%
100	$39.88	$41.50	$1.62	4.1%
500	$145.40	$145.49	$0.09	0.1%
1,000	$277.30	$275.48	($1.82)	-0.7%
1,500	$409.20	$405.48	($3.72)	-0.9%
2,500	$673.00	$665.46	($7.54)	-1.1%
5,000	$1,332.50	$1,315.42	($17.08)	-1.3%
7,500	$1,992.00	$1,965.38	($26.62)	-1.3%
10,000	$2,651.50	$2,615.34	($36.16)	-1.4%

Large Commercial Service (C22)		
Customer Charge	$100.00	$105.00
Distribution Margin Therms	$0.1718	$0.1742

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
10,001	$1,818	$1,848	$29	1.6%
12,500	$2,248	$2,283	$36	1.6%
15,000	$2,677	$2,719	$42	1.6%
17,500	$3,107	$3,154	$48	1.5%
20,000	$3,536	$3,590	$54	1.5%
25,000	$4,395	$4,461	$66	1.5%
30,000	$5,254	$5,332	$78	1.5%
45,000	$7,831	$7,946	$115	1.5%
75,000	$12,985	$13,173	$188	1.5%

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended June 30, 2008

Small Volume Industrial Service (I-30):		
Customer Charge	$13.50	$15.50
Distribution Margin Therms	$0.2356	$0.2388

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
50	$25.28	$27.44	$2.16	8.5%
100	$37.06	$39.38	$2.32	6.3%
500	$131.30	$134.90	$3.60	2.7%
1,000	$249.10	$254.29	$5.19	2.1%
1,500	$366.90	$373.69	$6.79	1.8%
2,500	$602.50	$612.48	$9.98	1.7%
5,000	$1,191.50	$1,209.46	$17.96	1.5%
7,500	$1,780.50	$1,806.43	$25.93	1.5%
10,000	$2,369.50	$2,403.41	$33.91	1.4%

Large Volume Industrial Service (I-32):		
Customer Charge	$100.00	$105.00
Distribution Margin Therms	$0.0952	$0.0966

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
10,001	$1,052.10	$1,071.20	$19.10	1.8%
15,000	$1,528.00	$1,554.15	$26.15	1.7%
20,000	$2,004.00	$2,037.21	$33.21	1.7%
30,000	$2,956.00	$3,003.31	$47.31	1.6%
50,000	$4,860.00	$4,935.51	$75.51	1.6%
75,000	$7,240.00	$7,350.77	$110.77	1.5%
100,000	$9,620.00	$9,766.03	$146.03	1.5%
125,000	$12,000.00	$12,181.29	$181.29	1.5%
150,000	$14,380.00	$14,596.54	$216.54	1.5%

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended June 30, 2008

Small Volume Public Authority (PA-40)		
Customer Charge	$13.50	$15.50
Distribution Margin Therms	$0.2593	$0.2598

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
50	$26.47	$28.49	$2.03	7.7%
100	$39.43	$41.48	$2.05	5.2%
500	$143.15	$145.41	$2.26	1.6%
1,000	$272.80	$275.32	$2.52	0.9%
1,500	$402.45	$405.24	$2.79	0.7%
2,500	$661.75	$665.06	$3.31	0.5%
5,000	$1,310.00	$1,314.62	$4.62	0.4%
7,500	$1,958.25	$1,964.18	$5.93	0.3%
10,000	$2,606.50	$2,613.74	$7.24	0.3%

Large Volume Public Authority (PA-42)		
Customer Charge	$100.00	$105.00
Distribution Margin Therms	$0.1198	$0.1216

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
10,001	$1,298.12	$1,321.48	$23.36	1.8%
15,000	$1,897.00	$1,929.54	$32.54	1.7%
20,000	$2,496.00	$2,537.71	$41.71	1.7%
30,000	$3,694.00	$3,754.07	$60.07	1.6%
50,000	$6,090.00	$6,186.79	$96.79	1.6%
75,000	$9,085.00	$9,227.68	$142.68	1.6%
100,000	$12,080.00	$12,268.57	$188.57	1.6%
125,000	$15,075.00	$15,309.47	$234.47	1.6%
150,000	$18,070.00	$18,350.36	$280.36	1.6%

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended June 30, 2008

Special Gas Light Service (PA-44):		
Customer Charge Lighting Group A	$15.17	$18.41
Customer Charge Lighting Group B	$18.20	$18.41

Average Montly Customers	Annual Bill Present	Annual Bill Proposed	Proposed Increase $	Proposed Increase %
The following is an annual delivery bill per lamp				
Customer Charge Lighting Group A	$182.04	$220.97	$38.93	21.4%
Customer Charge Lighting Group B	$218.40	$220.97	$2.57	1.2%

Note: There is no longer a Group A and Group B rate. All current customers are applicable to the Single Orifice Rate.

Irrigation Service (IR-60)		
Customer Charge	$13.50	$15.50
Distribution Margin Therms	$0.3192	$0.3235

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
50	$29.46	$31.68	$2.22	7.5%
100	$45.42	$47.85	$2.43	5.4%
500	$173.10	$177.25	$4.15	2.4%
1,000	$332.70	$339.01	$6.31	1.9%
1,500	$492.30	$500.76	$8.46	1.7%
2,500	$811.50	$824.27	$12.77	1.6%
5,000	$1,609.50	$1,633.05	$23.55	1.5%
7,500	$2,407.50	$2,441.82	$34.32	1.4%
10,000	$3,205.50	$3,250.59	$45.09	1.4%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
RESIDENTIAL SERVICE RATE R-10							
0	4	147,084	262,849	147,084	9.8%	262,849	0.4%
5	9	171,684	1,192,055	318,768	21.3%	1,454,904	2.1%
10	14	166,473	1,951,866	485,241	32.4%	3,406,770	5.0%
15	19	142,975	2,376,119	628,216	41.9%	5,782,889	8.5%
20	24	104,527	2,253,814	732,742	48.9%	8,036,703	11.8%
25	29	84,218	2,234,609	816,961	54.5%	10,271,312	15.1%
30	34	66,359	2,088,008	883,320	58.9%	12,359,320	18.2%
35	39	56,108	2,043,097	939,427	62.6%	14,402,416	21.2%
40	44	48,058	1,984,852	987,485	65.9%	16,387,268	24.1%
45	49	42,192	1,950,246	1,029,677	68.7%	18,337,514	26.9%
50	54	39,086	2,000,309	1,068,764	71.3%	20,337,823	29.9%
55	59	34,616	1,941,915	1,103,379	73.6%	22,279,738	32.7%
60	64	32,491	1,983,631	1,135,871	75.7%	24,263,369	35.6%
65	69	29,440	1,942,862	1,165,311	77.7%	26,206,230	38.5%
70	74	26,766	1,898,738	1,192,077	79.5%	28,104,968	41.3%
75	79	25,101	1,903,764	1,217,178	81.2%	30,008,732	44.1%
80	84	23,195	1,872,920	1,240,373	82.7%	31,881,652	46.8%
85	89	22,160	1,898,794	1,262,533	84.2%	33,780,446	49.6%
90	94	19,996	1,812,496	1,282,529	85.5%	35,592,943	52.3%
95	99	18,769	1,793,949	1,301,298	86.8%	37,386,892	54.9%
100	104	17,015	1,709,036	1,318,313	87.9%	39,095,928	57.4%
105	109	15,634	1,647,042	1,333,947	89.0%	40,742,969	59.9%
110	114	14,801	1,632,328	1,348,748	89.9%	42,375,297	62.3%
115	119	13,521	1,558,532	1,362,269	90.8%	43,933,829	64.5%
120	124	11,779	1,415,846	1,374,049	91.6%	45,349,675	66.6%
125	129	11,170	1,397,071	1,385,219	92.4%	46,746,747	68.7%
130	134	9,920	1,289,603	1,395,140	93.0%	48,036,349	70.6%
135	139	9,413	1,270,375	1,404,552	93.7%	49,306,724	72.4%
140	144	8,428	1,179,089	1,412,980	94.2%	50,485,813	74.2%
145	149	7,611	1,101,882	1,420,591	94.7%	51,587,695	75.8%
150	154	6,978	1,044,501	1,427,569	95.2%	52,632,196	77.3%
155	159	6,445	996,611	1,434,014	95.6%	53,628,806	78.8%
160	164	5,794	924,943	1,439,808	96.0%	54,553,749	80.1%
165	169	5,115	841,987	1,444,923	96.4%	55,395,736	81.4%
170	174	4,724	800,358	1,449,647	96.7%	56,196,095	82.6%
175	179	4,310	751,397	1,453,957	97.0%	56,947,492	83.7%
180	184	3,945	707,364	1,457,903	97.2%	57,654,856	84.7%
185	189	3,488	642,571	1,461,391	97.5%	58,297,427	85.6%
190	194	3,211	607,402	1,464,602	97.7%	58,904,829	86.5%
195	199	2,802	543,938	1,467,404	97.9%	59,448,767	87.3%
200	299	25,263	5,859,005	1,492,668	99.5%	65,307,772	95.9%
300	399	4,674	1,553,213	1,497,342	99.9%	66,860,985	98.2%
400	499	1,194	518,440	1,498,536	99.9%	67,379,425	99.0%
500	999	884	545,180	1,499,419	100.0%	67,924,605	99.8%
1,000	1,999	76	97,646	1,499,495	100.0%	68,022,251	99.9%
≥ 2,000		17	44,711	1,499,512	100.0%	68,066,962	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
RESIDENTIAL SERVICE RATE R-12							
0	4	5,459	12,331	5,459	6.4%	12,331	0.3%
5	9	10,624	76,405	16,082	18.9%	88,737	2.5%
10	14	10,301	125,639	26,384	31.1%	214,375	6.1%
15	19	9,085	156,305	35,469	41.8%	370,680	10.5%
20	24	6,551	146,395	42,019	49.5%	517,076	14.6%
25	29	5,236	144,026	47,255	55.6%	661,102	18.7%
30	34	4,038	131,678	51,293	60.4%	792,780	22.4%
35	39	3,373	127,317	54,667	64.4%	920,096	26.0%
40	44	3,032	129,564	57,699	67.9%	1,049,660	29.7%
45	49	2,653	127,105	60,352	71.1%	1,176,765	33.3%
50	54	2,453	130,177	62,805	74.0%	1,306,942	37.0%
55	59	2,074	120,537	64,879	76.4%	1,427,479	40.4%
60	64	2,031	128,330	66,910	78.8%	1,555,808	44.0%
65	69	1,801	123,134	68,711	80.9%	1,678,943	47.5%
70	74	1,663	122,206	70,374	82.9%	1,801,149	51.0%
75	79	1,530	120,151	71,904	84.7%	1,921,300	54.4%
80	84	1,361	113,847	73,265	86.3%	2,035,147	57.6%
85	89	1,300	115,400	74,565	87.8%	2,150,548	60.9%
90	94	1,140	107,205	75,706	89.1%	2,257,753	63.9%
95	99	1,045	103,439	76,750	90.4%	2,361,192	66.8%
100	104	903	94,006	77,653	91.4%	2,455,198	69.5%
105	109	823	89,783	78,476	92.4%	2,544,982	72.0%
110	114	787	89,920	79,263	93.3%	2,634,901	74.6%
115	119	661	78,915	79,923	94.1%	2,713,816	76.8%
120	124	557	69,294	80,480	94.8%	2,783,111	78.8%
125	129	504	65,386	80,985	95.4%	2,848,497	80.6%
130	134	458	61,736	81,443	95.9%	2,910,232	82.4%
135	139	445	62,184	81,887	96.4%	2,972,417	84.1%
140	144	362	52,346	82,249	96.9%	3,024,762	85.6%
145	149	349	52,376	82,598	97.3%	3,077,138	87.1%
150	154	258	39,939	82,856	97.6%	3,117,077	88.2%
155	159	230	36,871	83,086	97.8%	3,153,949	89.3%
160	164	209	34,441	83,295	98.1%	3,188,389	90.2%
165	169	167	28,511	83,462	98.3%	3,216,901	91.0%
170	174	194	34,100	83,656	98.5%	3,251,000	92.0%
175	179	137	24,682	83,793	98.7%	3,275,682	92.7%
180	184	128	23,850	83,921	98.8%	3,299,532	93.4%
185	189	126	24,112	84,048	99.0%	3,323,644	94.1%
190	194	98	19,125	84,145	99.1%	3,342,769	94.6%
195	199	108	21,712	84,253	99.2%	3,364,481	95.2%
200	299	591	139,942	84,844	99.9%	3,504,422	99.2%
300	399	70	23,854	84,914	100.0%	3,528,276	99.9%
400	499	7	3,151	84,921	100.0%	3,531,428	99.9%
500	999	3	2,008	84,924	100.0%	3,533,436	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
SMALL VOLUME COMMERCIAL RATE C-20							
0	9	45,637	93,478	45,637	33.4%	93,478	0.3%
10	19	11,797	162,319	57,434	42.0%	255,798	0.9%
20	29	7,608	180,216	65,042	47.6%	436,014	1.5%
30	39	5,567	187,261	70,609	51.7%	623,275	2.1%
40	49	4,652	202,215	75,261	55.1%	825,490	2.8%
50	59	3,958	210,633	79,219	58.0%	1,036,123	3.5%
60	69	3,356	211,655	82,575	60.4%	1,247,778	4.3%
70	79	2,886	210,179	85,461	62.6%	1,457,958	5.0%
80	89	2,573	212,899	88,034	64.4%	1,670,857	5.7%
90	99	2,264	209,493	90,298	66.1%	1,880,350	6.4%
100	109	2,137	218,373	92,436	67.7%	2,098,724	7.2%
110	119	1,947	217,863	94,382	69.1%	2,316,587	7.9%
120	129	1,757	214,256	96,139	70.4%	2,530,842	8.6%
130	139	1,558	205,156	97,698	71.5%	2,735,998	9.3%
140	149	1,480	209,601	99,178	72.6%	2,945,599	10.1%
150	159	1,434	216,925	100,612	73.6%	3,162,524	10.8%
160	169	1,310	211,315	101,922	74.6%	3,373,839	11.5%
170	179	1,173	200,443	103,095	75.5%	3,574,282	12.2%
180	189	1,124	202,795	104,219	76.3%	3,777,076	12.9%
190	199	1,085	206,800	105,304	77.1%	3,983,877	13.6%
200	249	4,395	960,820	109,699	80.3%	4,944,697	16.9%
250	299	3,384	906,615	113,083	82.8%	5,851,312	20.0%
300	349	2,746	871,124	115,829	84.8%	6,722,436	23.0%
350	399	2,247	823,754	118,076	86.4%	7,546,190	25.8%
400	449	1,958	813,951	120,033	87.9%	8,360,141	28.5%
450	499	1,713	796,260	121,747	89.1%	9,156,401	31.3%
500	599	2,650	1,419,229	124,397	91.1%	10,575,631	36.1%
600	699	2,002	1,267,932	126,399	92.5%	11,843,563	40.4%
700	799	1,545	1,129,873	127,944	93.6%	12,973,436	44.3%
800	899	1,212	1,005,484	129,155	94.5%	13,978,920	47.7%
900	999	916	849,267	130,071	95.2%	14,828,187	50.6%
1,000	1,499	2,912	3,475,058	132,984	97.3%	18,303,245	62.5%
1,500	1,999	1,443	2,438,885	134,426	98.4%	20,742,130	70.8%
2,000	2,999	1,145	2,706,208	135,572	99.2%	23,448,338	80.1%
3,000	3,999	416	1,391,628	135,988	99.5%	24,839,965	84.8%
4,000	4,999	183	793,480	136,170	99.7%	25,633,445	87.5%
5,000	5,999	132	712,597	136,303	99.8%	26,346,042	89.9%
6,000	6,999	84	533,014	136,387	99.8%	26,879,056	91.8%
7,000	7,999	62	455,483	136,449	99.9%	27,334,539	93.3%
8,000	8,999	37	303,016	136,486	99.9%	27,637,555	94.4%
9,000	9,999	39	358,260	136,524	99.9%	27,995,815	95.6%
10,000	10,999	32	323,236	136,556	100.0%	28,319,051	96.7%
11,000	11,999	22	244,189	136,578	100.0%	28,563,240	97.5%
12,000	12,999	13	156,847	136,590	100.0%	28,720,087	98.0%
13,000	13,999	1	13,058	136,591	100.0%	28,733,145	98.1%
14,000	14,999	9	127,467	136,600	100.0%	28,860,612	98.5%
≥ 15,000		20	431,045	136,620	100.0%	29,291,657	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
LARGE VOLUME COMMERCIAL RATE C-22							
0	249	51	2,411	51	30.4%	2,411	0.2%
250	499	15	5,249	66	39.1%	7,660	0.6%
500	749	15	9,297	80	47.8%	16,957	1.3%
750	999	1	914	81	48.4%	17,872	1.3%
1,000	1,999	2	2,561	83	49.5%	20,432	1.5%
2,000	2,999	2	5,483	85	50.5%	25,915	1.9%
3,000	3,999	5	19,333	90	53.8%	45,248	3.4%
4,000	4,999	3	13,056	93	55.4%	58,304	4.4%
5,000	5,999	7	41,464	100	59.8%	99,768	7.5%
6,000	6,999	6	42,774	107	63.6%	142,542	10.7%
7,000	7,999	3	21,534	110	65.2%	164,076	12.3%
8,000	8,999	4	32,672	113	67.4%	196,748	14.7%
9,000	9,999	3	26,598	116	69.0%	223,346	16.7%
10,000	19,999	34	564,529	150	89.1%	787,875	58.9%
20,000	29,999	12	295,317	162	96.2%	1,083,192	80.9%
30,000	39,999	5	161,749	166	98.9%	1,244,941	93.0%
40,000	49,999	1	46,128	167	99.5%	1,291,069	96.5%
50,000	59,999	1	47,176	168	100.0%	1,338,244	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
SMALL VOLUME INDUSTRIAL RATE I-30							
0	249	82	3,300	82	34.3%	3,300	0.6%
250	499	13	4,204	95	39.5%	7,503	1.4%
500	749	17	9,111	112	46.7%	16,614	3.0%
750	999	11	8,272	123	51.4%	24,886	4.5%
1,000	1,499	13	13,631	136	56.7%	38,517	7.0%
1,500	1,999	8	12,616	144	60.0%	51,133	9.2%
2,000	2,499	3	6,545	147	61.4%	57,678	10.4%
2,500	2,999	8	19,539	155	64.8%	77,217	13.9%
3,000	3,499	13	35,039	168	70.0%	112,255	20.3%
3,500	3,999	9	28,921	177	73.8%	141,176	25.5%
4,000	4,499	5	16,855	182	75.7%	158,031	28.5%
4,500	4,999	7	28,308	189	78.6%	186,339	33.6%
5,000	5,499	10	47,089	199	82.9%	233,428	42.2%
5,500	5,999	8	40,151	207	86.2%	273,579	49.4%
6,000	6,499	1	6,130	208	86.7%	279,709	50.5%
6,500	6,999	8	46,506	216	90.0%	326,215	58.9%
7,000	7,499	6	35,617	222	92.4%	361,832	65.3%
7,500	7,999	3	22,790	225	93.8%	384,622	69.5%
8,500	8,999	2	16,928	227	94.8%	401,550	72.5%
9,000	9,499	1	8,968	229	95.2%	410,518	74.1%
9,500	9,999	1	9,325	230	95.7%	419,843	75.8%
10,000	10,999	1	9,939	231	96.2%	429,782	77.6%
11,000	11,999	2	23,175	233	97.1%	452,957	81.8%
12,000	12,999	2	24,844	235	98.1%	477,800	86.3%
14,000	14,999	2	28,452	238	99.0%	506,252	91.4%
19,000	19,999	1	19,143	239	99.5%	525,395	94.9%
28,000	28,999	1	28,371	240	100.0%	553,766	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
LARGE VOLUME INDUSTRIAL RATE I-32							
0	499	9	517	9	15.7%	517	0.0%
500	999	3	2,178	12	20.0%	2,695	0.2%
1,000	1,999	1	1,570	13	21.4%	4,265	0.4%
3,000	3,999	1	3,182	14	22.9%	7,447	0.6%
4,000	4,999	2	8,248	15	25.7%	15,695	1.3%
5,000	9,999	9	91,679	25	41.4%	107,374	8.9%
10,000	14,999	11	160,059	36	60.0%	267,433	22.1%
15,000	19,999	10	205,704	46	77.1%	473,137	39.0%
20,000	29,999	6	162,332	52	87.1%	635,469	52.4%
30,000	39,999	2	66,882	54	90.0%	702,351	57.9%
40,000	49,999	1	40,506	55	91.4%	742,857	61.3%
50,000	59,999	1	52,592	56	92.9%	795,449	65.6%
60,000	69,999	2	128,029	57	95.7%	923,478	76.2%
75,000	125,000	3	289,176	60	100.0%	1,212,653	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
SMALL VOLUME PUBLIC AUTHORITY RATE P-40							
0	49	5,942	72,013	5,942	46.5%	72,013	1.3%
50	99	1,332	93,099	1,332	10.4%	165,112	2.9%
100	199	1,367	190,289	1,367	10.7%	355,400	6.3%
200	299	745	177,867	745	5.8%	533,268	9.5%
300	399	545	181,987	545	4.3%	715,255	12.7%
400	499	418	181,359	418	3.3%	896,614	16.0%
500	599	293	155,157	293	2.3%	1,051,772	18.7%
600	699	220	137,566	220	1.7%	1,189,337	21.2%
700	799	203	146,683	203	1.6%	1,336,021	23.8%
800	899	161	131,699	161	1.3%	1,467,720	26.2%
900	999	133	122,012	133	1.0%	1,589,732	28.3%
1,000	1,999	698	956,175	698	5.5%	2,545,906	45.4%
2,000	2,999	301	711,158	301	2.4%	3,257,065	58.1%
3,000	3,999	134	443,779	134	1.0%	3,700,844	66.0%
4,000	4,999	105	453,501	105	0.8%	4,154,345	74.0%
5,000	6,999	97	545,552	97	0.8%	4,699,896	83.8%
7,000	9,999	47	381,443	47	0.4%	5,081,339	90.6%
10,000	19,999	34	438,273	34	0.3%	5,519,612	98.4%
20,000	29,999	4	91,041	4	0.0%	5,610,653	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
LARGE VOLUME PUBLIC AUTHORITY RATE P-42							
600	799	1	605	1	1.7%	605	0.1%
800	999	2	1,742	3	5.0%	2,346	0.2%
1,000	5,999	4	5,281	7	11.7%	7,627	0.6%
6,000	7,999	4	26,637	11	18.3%	34,264	2.9%
8,000	9,999	5	41,881	16	26.7%	76,146	6.4%
10,000	12,999	8	89,684	24	40.0%	165,830	13.9%
13,000	15,999	3	44,641	27	45.0%	210,471	17.7%
16,000	18,999	5	82,950	32	53.3%	293,421	24.6%
19,000	23,999	6	115,842	38	63.3%	409,264	34.3%
24,000	26,999	8	199,194	46	76.7%	608,458	51.0%
27,000	29,999	3	82,833	49	81.7%	691,290	58.0%
30,000	39,999	4	135,070	53	88.3%	826,361	69.3%
40,000	59,999	5	235,294	58	96.7%	1,061,655	89.1%
60,000	70,000	2	130,475	60	100.0%	1,192,130	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
IRRIGATION SERVICE RATE I-60							
0	99	40	215	40	66.7%	215	0.2%
100	199	3	406	43	71.7%	620	0.6%
1,700	1,799	1	1,821	44	73.3%	2,441	2.4%
1,800	1,899	1	1,901	45	75.0%	4,343	4.2%
1,900	1,999	1	1,982	46	76.7%	6,325	6.1%
2,100	2,199	1	2,276	47	78.3%	8,600	8.3%
2,200	2,299	1	2,340	48	80.0%	10,941	10.6%
2,400	2,499	1	2,546	49	81.7%	13,486	13.0%
2,900	2,999	1	3,107	50	83.3%	16,593	16.0%
3,000	3,099	1	3,153	51	85.0%	19,746	19.1%
3,200	3,299	1	3,411	52	86.7%	23,157	22.4%
3,400	3,499	1	3,644	53	88.3%	26,802	25.9%
3,600	3,699	1	3,846	54	90.0%	30,647	29.6%
4,200	4,299	1	4,450	55	91.7%	35,098	33.9%
4,400	4,499	1	4,654	56	93.3%	39,751	38.4%
10,500	10,599	1	10,996	57	95.0%	50,747	49.0%
11,900	11,999	1	12,416	58	96.7%	63,163	61.0%
16,900	16,999	1	17,693	59	98.3%	80,856	78.1%
21,700	21,799	1	22,699	60	100.0%	103,554	100.0%

UNS GAS, INC.

DOCKET NO. G-04204A-08-0571

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 8, 2009

DIRECT TESTIMONY OF WILLIAM A. RIGSBY, CRRA

EXECUTIVE SUMMARY

Original Cost of Equity Capital – The Residential Utility Consumer Office ("RUCO") recommends an 8.61 percent original cost of equity capital for UNS Gas, Inc. ("UNSG" or "Company"). This 8.61 percent original cost figure is based on the results obtained in a cost of equity analysis, which employed both the Discounted Cash Flow ("DCF") and Capital Asset Pricing Model ("CAPM") methodologies. RUCO's recommended 8.61 percent figure is 239 basis points lower than the Company-proposed cost of equity capital of 11.00 percent.

Cost of Debt – Based on a review of the costs associated with UNSG's various debt instruments, RUCO recommends that the Company-proposed 6.49 percent cost of debt be adopted by the Arizona Corporation Commission ("ACC" or "Commission").

Capital Structure – RUCO recommends that the Company-proposed capital structure, which is comprised of 50.01 percent debt and 49.99 percent common equity, be adopted by the Commission.

Original Cost Rate of Return – Based on the results of RUCO's recommended capital structure, original cost of equity capital, and debt analyses, RUCO recommends a 7.55 percent original cost rate of return ("OCROR") for UNSG. This figure represents the weighted average cost of RUCO's recommended 8.61

percent original cost of equity capital and RUCO's 6.49 percent recommended cost of debt. RUCO's recommended 7.55 percent OCROR is 120 basis points lower than the Company-proposed unadjusted 8.75 percent weighted average cost of capital.

Fair Value Rate of Return – RUCO is recommending a 5.38 percent fair value rate of return ("FVROR") which is 217 basis points lower than RUCO's recommended 7.55 percent OCROR. In arriving at this 5.38 percent FVROR figure, RUCO considered a range of possible returns that could be applied to the Company's fair value rate base. The method that RUCO used to arrive at its recommended 5.38 percent FVROR comports with the provisions of Decision No. 70441, dated July 28, 2008, that resulted from a prior remand proceeding which involved Chaparral City Water Company. The methodology that RUCO relied on to arrive at its recommended FVROR figure is explained fully in the testimony of RUCO witness Ralph Smith.

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INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My Name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please describe your qualifications in the field of utilities regulation and your educational background.

A. I have been involved with utilities regulation in Arizona since 1994. During that period of time I have worked as a utilities rate analyst for both the Arizona Corporation Commission ("ACC" or "Commission") and for RUCO. I hold a Bachelor of Science degree in the field of finance from Arizona State University and a Master of Business Administration degree, with an emphasis in accounting, from the University of Phoenix. I have also been awarded the professional designation, Certified Rate of Return Analyst ("CRRA") by the Society of Utility and Regulatory Financial Analysts ("SURFA"). The CRRA designation is awarded based upon experience and the successful completion of a written examination. Appendix I, which is attached to this testimony, further describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations that are based on my analysis of UNS Gas, Inc.'s ("UNSG" or "Company") application for a permanent rate increase ("Application") for the Company's natural gas distribution operations in northern Arizona and Santa Cruz County in southern Arizona. UNSG filed the Application with the ACC on November 7, 2008. The Company has chosen the fiscal year ended June 30, 2008 for the test year in this proceeding.

Q. Briefly describe UNSG.

A. UNSG serves customers in a number of areas in northern Arizona including Flagstaff, Kingman and Prescott. The Company also provides service to customers in Santa Cruz County in the southern half of the state. UNSG is a wholly owned subsidiary of UniSource Energy Services, which is owned by UniSource Energy Corporation ("UniSource" or "Parent"), an Arizona corporation, based in Tucson, that is publicly traded on the New York Stock Exchange ("NYSE")[1]. UniSource is also the parent company of Tucson Electric Power, the second largest investor owned electric utility in the state. In addition to natural gas distribution, UniSource also provides electric service through its other subsidiary UNS Electric, Inc., to customers in Mohave and Santa Cruz Counties.

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[1] NYSE ticker symbol UNS.

Q. Please explain your role in RUCO's analysis of UNSG's Application.

A. I reviewed UNSG's Application and performed a cost of capital analysis to determine a fair rate of return on the Company's invested capital. In addition to my recommended capital structure, my direct testimony will present my recommended costs of common equity and my recommended cost of long-term debt (the Company has no short-term debt or preferred stock). The recommendations contained in this testimony are based on information obtained from Company responses to data requests, the Company's Application and from market-based research that I conducted during my analysis.

Q. Is this your first case involving UNSG?

A. No. In 2003 I was involved with UniSource's acquisition of UniSource Energy Corporation's gas and electric assets from Citizens' Utilities Company. The UNSG entity was the result of that acquisition. I also provided cost of capital testimony in the Company's most recent rate case proceeding which resulted in Decision No. 70011, dated November 27, 2007. UNSG's present rates were established in that Decision.

...

Q. Were you also responsible for conducting an analysis of the Company's proposed revenue level, rate base and rate design?

A. No. Those aspects of the case were handled by two outside consultants. Mr. Ralph Smith, of Larkin & Associates, will provide testimony on RUCO's recommended level of required revenue (based on his adjustments to Company-proposed levels of rate base and operating expense). Mr. Smith will also provide testimony on the methodology that RUCO employed to arrive at its recommended rate of return on UNSG's fair value rate base. Mr. Frank Radigan, of Hudson River Energy Group, will provide testimony on RUCO's recommended rate design.

Q. What areas will you address in your testimony?

A. I will address the cost of capital issues associated with the case.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Schedules WAR-1 through WAR-9.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your cost of capital testimony is organized.

A. My cost of capital testimony is organized into seven sections. First, the introduction I have just presented and second, the summary of my testimony that I am about to give. Third, I will present the findings of my cost of equity capital analysis, which utilized both the discounted cash flow

("DCF") method, and the capital asset pricing model ("CAPM"). These are the two methods that RUCO and ACC Staff have consistently used for calculating the cost of equity capital in rate case proceedings in the past, and are the methodologies that the ACC has given the most weight to in setting allowed rates of returns for utilities that operate in the Arizona jurisdiction. In this second section I will also provide a brief overview of the economic climate that UNSG is currently operating in. Fourth, I will discuss my recommended cost of debt. Fifth, I will compare my recommended capital structure with the Company-proposed capital structure. Sixth, I will explain my weighted cost of capital recommendation and seventh, I will comment on UNSG's cost of capital testimony. Schedules WAR-1 through WAR-9 will provide support for my cost of capital analysis.

Q. Please summarize the recommendations and adjustments that you will address in your testimony.

A. Based on the results of my analysis of UNSG, I am making the following recommendations:

Original Cost of Equity Capital – I am recommending an 8.61 percent original cost of equity capital. This 8.61 percent original cost figure is based on the results that I obtained in my cost of equity analysis, which employed both the DCF and CAPM methodologies. My recommended

8.61 percent figure is 239 basis points lower than the Company-proposed cost of equity capital of 11.00 percent.

Cost of Debt – Based on my review of the costs associated with UNSG's various debt instruments, I am recommending that the Company-proposed 6.49 percent cost of debt be adopted by the Commission.

Capital Structure – I am recommending that the Company-proposed capital structure, which is comprised of 50.01 percent debt and 49.99 percent common equity, be adopted by the Commission.

Original Cost Rate of Return – Based on the results of my recommended capital structure, original cost of equity capital, and debt analyses, I am recommending a 7.55 percent original cost rate of return ("OCROR") for UNSG. This figure represents the weighted average cost of my recommended 8.61 percent original cost of equity capital and my 6.49 percent recommended cost of debt. My recommended 7.55 percent OCROR is 120 basis points lower than the Company-proposed unadjusted 8.75 percent weighted average cost of capital.

Fair Value Rate of Return – RUCO is recommending a 5.38 percent fair value rate of return ("FVROR") which is 217 basis points lower than my recommended 7.55 percent OCROR. In arriving at this 5.38 percent

FVROR figure RUCO considered a range of possible returns that could be applied to the Company's fair value rate base. The method that RUCO used to arrive at its recommended 5.38 percent FVROR comports with the provisions of Decision No. 70441, dated July 28, 2008, which resulted from a prior remand proceeding which involved Chaparral City Water Company.[2] The methodology that RUCO relied on to arrive at its recommended FVROR figure is explained fully in the testimony of RUCO witness Ralph Smith.

Q. Please explain why RUCO is recommending two different rates of return in this case?

A. UNSG Gas has chosen to use an average of the Company's original cost rate base ("OCRB"), which is based on the original book value of plant assets, and a rate base derived from a reconstruction cost new study ("RCND"), which takes general inflation into consideration, to arrive at a fair value rate base ("FVRB") which reflects the current dollar value of UNSG's original cost rate base. Because general inflation is also reflected in my OCROR figure, it is inappropriate to apply it to an OCRB. To do so would result in a double counting of inflation. For this reason RUCO has derived a FVROR which reduces my recommended OCROR by an inflation factor of 217 basis points.

[2] Chaparral City Water Company has appealed that Decision. The appeal is currently pending before the Arizona Court of Appeals.

Q. Can you explain further why it is necessary to determine an inflation factor adjustment to arrive at an OCROR?

A. Yes. Unless a utility elects to forego an RCND study that restates the value of the OCRB in current dollars, and agrees to use its OCRB as its FVRB, the utility's FVRB is calculated by averaging its OCRB and its RCND rate bases. Because an RCND study restates the OCRB in current dollars (through the use of engineering indexes that contain certain inflation factors to calculate an RCND rate base), it is inappropriate to apply an OCROR to a FVRB. This is because the OCROR, like the FVRB, contains an inflation component in it. Consequently, the application of the OCRB rate of return to a FVRB (calculated using the average of an OCRB and the RCND rate base) produces an inappropriate level of operating income which reflects an over-counting of the effects of inflation. As a result, a utility's investors would earn additional operating income on the effects of inflation, as opposed to only earning a return on actual investor supplied capital. To remedy this situation, the OCROR is adjusted downward by removing the inflation expectation that is embedded in it.[3] This is the same rationale that the Commission relied on in Decision No. 70441.

...

[3] In a case where there is deflation, an upward adjustment would be made to account for a level of deflation.

Q. Why do you believe that RUCO's recommended 5.38 percent FVROR is an appropriate rate of return for UNSG to earn on its invested capital?

A. The FVROR that RUCO is recommending meets the criteria established in the landmark Supreme Court cases of Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944). Simply stated, these two cases affirmed that a public utility that is efficiently and economically managed is entitled to a return on investment that instills confidence in its financial soundness, allows the utility to attract capital, and also allows the utility to perform its duty to provide service to ratepayers. The rate of return adopted for the utility should also be comparable to a return that investors would expect to receive from investments with similar risk.

The Hope decision allows for the rate of return to cover both the operating expenses and the "capital costs of the business" which includes interest on debt and dividend payment to shareholders. This is predicated on the belief that, in the long run, a company that cannot meet its debt obligations and provide its shareholders with an adequate rate of return will not continue to supply adequate public utility service to ratepayers.

...

Q. Do the Bluefield and Hope decisions indicate that a rate of return sufficient to cover all operating and capital costs is guaranteed?

A. No. Neither case *guarantees* a rate of return on utility investment. What the Bluefield and Hope decisions *do allow*, is for a utility to be provided with the *opportunity* to earn a reasonable rate of return on its investment. That is to say that a utility, such as UNSG, is provided with the opportunity to earn an appropriate rate of return if the Company's management exercises good judgment and manages its assets and resources in a manner that is both prudent and economically efficient.

COST OF EQUITY CAPITAL

Q. What is your recommended cost of equity capital for UNSG?

A. Based on the results of my DCF and CAPM analyses, which ranged from 5.26 percent to 11.40 percent for a sample of local distribution companies ("LDC"), I am recommending an 8.61 percent original cost of equity capital for UNSG. My recommended original cost of equity capital figure represents an average of the results of my DCF and CAPM analyses, which utilized a sample of publicly traded natural gas local distribution companies ("LDC").

Discounted Cash Flow (DCF) Method

Q. Please explain the DCF method that you used to estimate UNSG's cost of equity capital.

A. The DCF method employs a stock valuation model known as the constant growth valuation model, that bears the name of Dr. Myron J. Gordon (i.e. the Gordon model), the professor of finance who was responsible for its development. Simply stated, the DCF model is based on the premise that the current price of a given share of common stock is determined by the present value of all of the future cash flows that will be generated by that share of common stock. The rate that is used to discount these cash flows back to their present value is often referred to as the investor's cost of capital (i.e. the cost at which an investor is willing to forego other investments in favor of the one that he or she has chosen).

Another way of looking at the investor's cost of capital is to consider it from the standpoint of a company that is offering its shares of stock to the investing public. In order to raise capital, through the sale of common stock, a company must provide a required rate of return on its stock that will attract investors to commit funds to that particular investment. In this respect, the terms "cost of capital" and "investor's required return" are one in the same. For common stock, this required return is a function of the dividend that is paid on the stock. The investor's required rate of return can be expressed as the percentage of the dividend that is paid on the stock (dividend yield) plus an expected rate of future dividend growth. This is illustrated in mathematical terms by the following formula:

$$k = \frac{D_1}{P_0} + g$$

where: k = the required return (cost of equity, equity capitalization rate),

$\frac{D_1}{P_0}$ = the dividend yield of a given share of stock calculated by dividing the expected dividend by the current market price of the given share of stock, and

g = the expected rate of future dividend growth

This formula is the basis for the standard growth valuation model that I used to determine UNSG's cost of equity capital.

Q. In determining the rate of future dividend growth for UNSG, what assumptions did you make?

A. There are two primary assumptions regarding dividend growth that must be made when using the DCF method. First, dividends will grow by a constant rate into perpetuity, and second, the dividend payout ratio will remain at a constant rate. Both of these assumptions are predicated on the traditional DCF model's basic underlying assumption that a company's earnings, dividends, book value and share growth all increase at the same constant rate of growth into infinity. Given these assumptions, if the dividend payout ratio remains constant, so does the earnings retention ratio (the percentage of earnings that are retained by the company as opposed to being paid out in dividends). This being the case, a company's dividend growth can be measured by multiplying its retention ratio (1 - dividend payout ratio) by its book return on equity. This can be stated as g = b x r.

Q. Would you please provide an example that will illustrate the relationship that earnings, the dividend payout ratio and book value have with dividend growth?

A. RUCO consultant Stephen Hill illustrated this relationship in a Citizens Utilities Company 1993 rate case by using a hypothetical utility.[4]

Table I

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.25	$11.70	4.00%
Equity Return	10%	10%	10%	10%	10%	N/A
Earnings/Sh.	$1.00	$1.04	$1.082	$1.125	$1.170	4.00%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.649	$0.675	$0.702	4.00%

Table I of Mr. Hill's illustration presents data for a five-year period on his hypothetical utility. In Year 1, the utility had a common equity or book

[4] Citizens Utilities Company, Arizona Gas Division, Docket No. E-1032-93-111, Prepared Testimony, dated December 10, 1993, p. 25.

value of $10.00 per share, an investor-expected equity return of ten percent, and a dividend payout ratio of sixty percent. This results in earnings per share of $1.00 ($10.00 book value x 10 percent equity return) and a dividend of $0.60 ($1.00 earnings/sh. x 0.60 payout ratio) during Year 1. Because forty percent (1 - 0.60 payout ratio) of the utility's earnings are retained as opposed to being paid out to investors, book value increases to $10.40 in Year 2 of Mr. Hill's illustration. Table I presents the results of this continuing scenario over the remaining five-year period.

The results displayed in Table I demonstrate that under "steady-state" (i.e. constant) conditions, book value, earnings and dividends all grow at the same constant rate. The table further illustrates that the dividend growth rate, as discussed earlier, is a function of (1) the internally generated funds or earnings that are retained by a company to become new equity, and (2) the return that an investor earns on that new equity. The DCF dividend growth rate, expressed as $g = b \times r$, is also referred to as the internal or sustainable growth rate.

Q. If earnings and dividends both grow at the same rate as book value, shouldn't that rate be the sole factor in determining the DCF growth rate?

A. No. Possible changes in the expected rate of return on either common equity or the dividend payout ratio make earnings and dividend growth by themselves unreliable. This can be seen in the continuation of Mr. Hill's illustration on a hypothetical utility.

Table II

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.47	$12.158	5.00%
Equity Return	10%	10%	15%	15%	15%	10.67%
Earnings/Sh	$1.00	$1.04	$1.623	$1.720	$1.824	16.20%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.974	$1.032	$1.094	16.20%

In the example displayed in Table II, a sustainable growth rate of four percent[5] exists in Year 1 and Year 2 (as in the prior example). In Year 3, Year 4 and Year 5, however, the sustainable growth rate increases to six percent.[6] If the hypothetical utility in Mr. Hill's illustration were expected to earn a fifteen-percent return on common equity on a continuing basis, then a six percent long-term rate of growth would be reasonable. However, the compound growth rate for earnings and dividends, displayed in the last column, is 16.20 percent. If this rate was to be used in the DCF model, the utility's return on common equity would be expected to increase by fifty percent every five years, [(15 percent ÷ 10 percent) – 1]. This is clearly an unrealistic expectation.

[5] [(Year 2 Earnings/Sh – Year 1 Earnings/Sh) ÷ Year 1 Earnings/Sh] = [($1.04 - $1.00) ÷ $1.00] = [$0.04 ÷ $1.00] = 4.00%

[6] [(1 – Payout Ratio) x Rate of Return] = [(1 - 0.60) x 15.00%] = 0.40 x 15.00% = 6.00%

Although it is not illustrated in Mr. Hill's hypothetical example, a change in only the dividend payout ratio will eventually result in a utility paying out more in dividends than it earns. While it is not uncommon for a utility in the real world to have a dividend payout ratio that exceeds one hundred percent on occasion, it would be unrealistic to expect the practice to continue over a sustained long-term period of time.

Q. Other than the retention of internally generated funds, as illustrated in Mr. Hill's hypothetical example, are there any other sources of new equity capital that can influence an investor's growth expectations for a given company?

A. Yes, a company can raise new equity capital externally. The best example of external funding would be the sale of new shares of common stock. This would create additional equity for the issuer and is often the case with utilities that are either in the process of acquiring smaller systems or providing service to rapidly growing areas.

Q. How does external equity financing influence the growth expectations held by investors?

A. Rational investors will put their available funds into investments that will either meet or exceed their given cost of capital (i.e. the return earned on their investment). In the case of a utility, the book value of a company's stock usually mirrors the equity portion of its rate base (the utility's earning base). Because regulators allow utilities the opportunity to earn a reasonable rate of return on rate base, an investor would take into consideration the effect that a change in book value would have on the rate of return that he or she would expect the utility to earn. If an investor believes that a utility's book value (i.e. the utility's earning base) will increase, then he or she would expect the return on the utility's common stock to increase. If this positive trend in book value continues over an extended period of time, an investor would have a reasonable expectation for sustained long-term growth.

Q. Please provide an example of how external financing affects a utility's book value of equity.

A. As I explained earlier, one way that a utility can increase its equity is by selling new shares of common stock on the open market. If these new shares are purchased at prices that are higher than those shares sold previously, the utility's book value per share will increase in value. This would increase both the earnings base of the utility and the earnings expectations of investors. However, if new shares sold at a price below the pre-sale book value per share, the after-sale book value per share declines in value. If this downward trend continues over time, investors might view this as a decline in the utility's sustainable growth rate and will have lower expectations regarding growth. Using this same logic, if a new stock issue sells at a price per share that is the same as the pre-sale book value per share, there would be no impact on either the utility's earnings base or investor expectations.

Q. Please explain how the external component of the DCF growth rate is determined.

A. In his book, The Cost of Capital to a Public Utility,[7] Dr. Gordon (the individual responsible for the development of the DCF or constant growth model) identified a growth rate that includes both expected internal and external financing components. The mathematical expression for Dr. Gordon's growth rate is as follows:

$$g = (br) + (sv)$$

where:	g	=	DCF expected growth rate,
	b	=	the earnings retention ratio,
	r	=	the return on common equity,
	s	=	the fraction of new common stock sold that accrues to a current shareholder, and
	v	=	funds raised from the sale of stock as a fraction of existing equity.
and	v	=	1 - [(BV) ÷ (MP)]
where:	BV	=	book value per share of common stock, and
	MP	=	the market price per share of common stock.

[7] Gordon, M.J., The Cost of Capital to a Public Utility, East Lansing, MI: Michigan State University, 1974, pp. 30-33.

Q. Did you include the effect of external equity financing on long-term growth rate expectations in your analysis of expected dividend growth for the DCF model?

A. Yes. The external growth rate estimate (sv) is displayed on Page 1 of Schedule WAR-4, where it is added to the internal growth rate estimate (br) to arrive at a final sustainable growth rate estimate.

Q. Please explain why your calculation of external growth on page 2 of Schedule WAR-4, is the current market-to-book ratio averaged with 1.0 in the equation [(M ÷ B) + 1] ÷ 2.

A. The market price of a utility's common stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital (one of the desired effects of regulation). As a result of this situation, I used [(M ÷ B) + 1] ÷ 2 as opposed to the current market-to-book ratio by itself to represent investor's expectations that, in the future, a given utility will achieve a market-to-book ratio of 1.0.

Q. Has the Commission ever adopted a cost of capital estimate that included this assumption?

A. Yes. In a prior Southwest Gas Corporation rate case[8], the Commission adopted the recommendations of ACC Staff's cost of capital witness, Stephen Hill, who I noted earlier in my testimony. In that case, Mr. Hill

[8] Decision No. 68487, Dated February 23, 2006 (Docket No. G-01551A-04-0876)

used the same methods that I have used in arriving at the inputs for the DCF model. His final recommendation for Southwest Gas Corporation was largely based on the results of his DCF analysis, which incorporated the same valid market-to-book ratio assumption that I have used consistently in the DCF model as a cost of capital witness for RUCO.

Q. How did you develop your dividend growth rate estimate?

A. I analyzed data on two separate proxy groups. A water company proxy group comprised of three publicly traded water companies and a natural gas proxy group consisting of ten natural gas local distribution companies ("LDC") that have similar operating characteristics to water providers.

Q. Why did you use a proxy group methodology as opposed to a direct analysis of UNSG?

A. One of the problems in performing this type of analysis is that the utility applying for a rate increase is not always a publicly traded company, as is the case with UNSG itself. Consequently it was necessary to create a proxy by analyzing publicly traded water companies and LDC's with similar risk characteristics.

Q. Are there any other advantages to the use of a proxy?

A. Yes. As I noted earlier, the U.S. Supreme Court ruled in the Hope decision that a utility is entitled to earn a rate of return that is commensurate with the returns on investments of other firms with comparable risk. The proxy technique that I have used derives that rate of return. One other advantage to using a sample of companies is that it reduces the possible impact that any undetected biases, anomalies, or measurement errors may have on the DCF growth estimate.

Q. What criteria did you use in selecting the companies that make up your proxy for UNSG?

A. All of the LDC's in my sample are publicly traded on the NYSE and are followed by The Value Line Investment Survey's ("Value Line") natural gas (distribution) industry segment. All of the companies in the proxy are engaged in the provision of regulated natural gas distribution services. Attachment A of my testimony contains Value Line's most recent evaluation of the natural gas proxy group that I used for my cost of common equity analysis.

Q. What companies are included your proxy?

A. The ten natural gas LDC's included in my proxy (and their NYSE ticker symbols) are AGL Resources, Inc. ("AGL"), Atmos Energy Corp. ("ATO"), Laclede Group, Inc. ("LG"), New Jersey Resources Corporation ("NJR"), Nicor, Inc. ("GAS"), Northwest Natural Gas Co. ("NWN"), Piedmont Natural Gas Company ("PNY"), South Jersey Industries, Inc. ("SJI")

Southwest Gas Corporation ("SWX"), which is the dominant natural gas provider in Arizona, and WGL Holdings, Inc. ("WGL").

Q. Briefly describe the regions of the U.S. served by the ten natural gas LDC's that make up your sample proxy.

A. The ten LDC's listed above provide natural gas service to customers in the Middle Atlantic region (i.e. NJI which serves portions of northern New Jersey, SJI which serves southern New Jersey and WGL which serves the Washington D.C. metro area), the Southeast and South Central portions of the U.S. (i.e. AGL which serves Virginia, southern Tennessee and the Atlanta, Georgia area and PNY which serves customers in North Carolina, South Carolina and Tennessee), the South, deep South and Midwest (i.e. ATO which serves customers in Kentucky, Mississippi, Louisiana, Texas, Colorado and Kansas, GAS which provides service to northern and western Illinois, and LG which serves the St. Louis area), and the Pacific Northwest (i.e. NWN which serves Washington state and Oregon). Portions of Arizona, Nevada and California are served by SWX.

Q. Did the Company's witness also perform a similar analysis using natural gas LDC's?

A. Yes, the Company's witness, Kentton C. Grant, performed a similar analysis of publicly traded LDC's.

Q. Does your sample of LDC's include all of the same LDC's that Mr. Grant included in his sample?

A. Yes.

Q. Please explain your DCF growth rate calculations for the sample companies used in your proxy.

A. Schedule WAR-5 provides retention ratios, returns on book equity, internal growth rates, book values per share, numbers of shares outstanding, and the compounded share growth for each of the utilities included in the sample for the historical observation period 2004 to 2008. Schedule WAR-5 also includes Value Line's projected 2009, 2010 and 2012-14 values for the retention ratio, equity return, book value per share growth rate, and number of shares outstanding for the LDC's in my sample.

Q. Please describe how you used the information displayed in Schedule WAR-5 to estimate each comparable utility's dividend growth rate.

A. In explaining my analysis, I will use AGL Resources, Inc., (NYSE symbol AGL) as an example. The first dividend growth component that I evaluated was the internal growth rate. I used the "b x r" formula (described on pages 9 and 10) to multiply AGL's earned return on common equity by its earnings retention ratio for each year during the 2004 to 2008 observation period to derive the utility's annual internal growth rates. I used the mean average of this five-year period as a benchmark against which I compared the projected growth rate trends provided by Value Line. Because an investor is more likely to be influenced by recent growth trends, as opposed to historical averages, the five-year mean noted earlier was used only as a benchmark figure. As shown on Schedule WAR-5, Page 1, AGL's sustainable internal growth rate increased from 5.45% in 2004 to 6.14% in 2005. The company's growth rates experienced a pattern of decline during the remainder of the observation period, which resulted in a 5.49% average over the 2004 to 2008 time frame. Value Line's analysts are forecasting this trend to continue through 2009 before growth climbs steadily to 5.98% through the 2012-14 period. Based on these estimates I believe a 5.30% rate of internal growth is reasonable for AGL (Schedule WAR-4, Page 1, Column A, Line 1).

Q. Please continue with the external growth rate "s x v" component portion of your analysis.

A. Schedule WAR-5 demonstrates that AGL's share growth averaged just 0.07% over the observation period. Value Line expects future outstanding shares to increase from 76.90 million in 2008 to 85.00 million by the end of 2014. Taking this data into consideration, I am estimating a 1.75% rate of share growth for AGL (Schedule WAR-4, Page 2, Column A, Line 1). I used this estimate to calculate the s x v component of the DCF dividend growth rate. My final dividend growth rate estimate for AGL is 5.58

percent (5.30 percent internal growth + 0.28 percent external growth) and is shown on Page 1 of Schedule WAR-4.

Q. What is your average dividend growth rate estimate using the DCF model for the sample natural gas utilities?

A. Based on the DCF model, my average dividend growth rate estimate is 6.45 percent, which is also displayed on page 1 of Schedule WAR-4.

Q. How do your average dividend growth rate estimates compare with the growth rate data published by Value Line and other analysts?

A. My 6.45 percent estimate is 14 basis points lower than the 6.59 percent consensus projections published by Zacks Investment Research ("Zacks"), exhibited in my Attachment B, and 12 basis points higher than Value Line's 4.33 percent projected estimates. As can also be seen on Schedule WAR-6, the 6.45 percent estimate that I have calculated is 77 basis points higher than the 5.68 percent five-year historical average of Value Line data (on EPS, DPS and BVPS) and is 123 basis point higher than the 5.22 percent average of the 5-year EPS means provided by Zacks, and the aforementioned percent five-year historical average of Value Line data. In fact, my 6.45 percent estimate is 383 basis points higher than the 2.62 percent Value Line 5-year compound history that is also displayed on Schedule WAR-6. Based on the information presented in Schedule WAR-6, I would say that my 6.45 percent estimate, which falls between Zack's and Value Line's projections, is a fair representation of the growth estimates presented by securities analysts at this point in time.

Q. How did you calculate the dividend yields displayed in Schedule WAR-3?

A. I used the estimated annual dividends, for the next twelve-month period, that appeared in Value Line's March 13, 2009 Ratings and Reports Natural Gas Utility update. I then divided those figures by the eight-week average price per share of the appropriate utility's common stock. The eight-week average price is based on the daily closing stock prices for each of the companies in my proxies for the period March 30, 2009 to May 22, 2009.

Q. Based on the results of your DCF analysis, what is your cost of equity capital estimate for the LDC's included in your sample?

A. As shown in Schedule WAR-2, the cost of equity capital derived from my DCF analysis is 11.40 percent.

Capital Asset Pricing Model (CAPM) Method

Q. Please explain the theory behind CAPM and why you decided to use it as an equity capital valuation method in this proceeding.

A. CAPM is a mathematical tool that was developed during the early 1960's by William F. Sharpe[9], the Timken Professor Emeritus of Finance at Stanford University, who shared the 1990 Nobel Prize in Economics for research that eventually resulted in the CAPM model. CAPM is used to analyze the relationships between rates of return on various assets and risk as measured by beta.[10] In this regard, CAPM can help an investor to determine how much risk is associated with a given investment so that he or she can decide if that investment meets their individual preferences. Finance theory has always held that as the risk associated with a given investment increases, so should the expected rate of return on that investment and vice versa. According to CAPM theory, risk can be classified into two specific forms: nonsystematic or diversifiable risk, and systematic or non-diversifiable risk. While nonsystematic risk can be virtually eliminated through diversification (i.e. by including stocks of various companies in various industries in a portfolio of securities), systematic risk, on the other hand, cannot be eliminated by diversification.

[9] William F. Sharpe, "A Simplified Model of Portfolio Analysis," Management Science, Vol. 9, No. 2 (January 1963), pp. 277-93.

[10] Beta is defined as an index of volatility, or risk, in the return of an asset relative to the return of a market portfolio of assets. It is a measure of systematic or non-diversifiable risk. The returns on a stock with a beta of 1.0 will mirror the returns of the overall stock market. The returns on stocks with betas greater than 1.0 are more volatile or riskier than those of the overall stock market; and if a stock's beta is less than 1.0, its returns are less volatile or riskier than the overall stock market.

Thus, systematic risk is the only risk of importance to investors. Simply stated, the underlying theory behind CAPM states that the expected return on a given investment is the sum of a risk-free rate of return plus a market risk premium that is proportional to the systematic (non-diversifiable risk) associated with that investment. In mathematical terms, the formula is as follows:

$$k = r_f + [\, ß\, (r_m - r_f)\,]$$

where: k = the expected return of a given security,

r_f = risk-free rate of return,

$ß$ = beta coefficient, a statistical measurement of a security's systematic risk,

r_m = average market return (e.g. S&P 500), and

$r_m - r_f$ = market risk premium.

Q. What types of financial instruments are generally used as a proxy for the risk-free rate of return in the CAPM model?

A. Generally speaking, the yields of U.S. Treasury instruments are used by analysts as a proxy for the risk-free rate of return component.

. . .

Q. Please explain why U.S. Treasury instruments are regarded as a suitable proxy for the risk-free rate of return?

A. As citizens and investors, we would like to believe that U.S. Treasury securities (which are backed by the full faith and credit of the United States Government) pose no threat of default no matter what their maturity dates are. However, a comparison of various Treasury instruments will reveal that those with longer maturity dates do have slightly higher yields. Treasury yields are comprised of two separate components,[11] a real rate of interest (believed to be approximately 2.00 percent) and an inflationary expectation. When the real rate of interest is subtracted from the total treasury yield, all that remains is the inflationary expectation. Because increased inflation represents a potential capital loss, or risk, to investors, a higher inflationary expectation by itself represents a degree of risk to an investor. Another way of looking at this is from an opportunity cost standpoint. When an investor locks up funds in long-term T-Bonds, compensation must be provided for future investment opportunities foregone. This is often described as maturity or interest rate risk and it can affect an investor adversely if market rates increase before the instrument matures (a rise in interest rates would decrease the value of the debt instrument). As discussed earlier in the DCF portion of my

[11] As a general rule of thumb, there are three components that make up a given interest rate or rate of return on a security: the real rate of interest, an inflationary expectation, and a risk premium. The approximate risk premium of a given security can be determined by simply subtracting a 91-day T-Bill rate from the yield on the security.

testimony, this compensation translates into higher rates of returns to the investor.

Q. What security did you use for a risk-free rate of return in your CAPM analysis?

A. I used an eight-week average of the yields on a 5-year U.S. Treasury instrument. The yields were published in Value Line's Selection and Opinion publication dated April 3, 2009 through May 22, 2009 (Attachment C). This resulted in a risk-free (r_f) rate of return of 1.87 percent.

Q. Why did you use the yield on a 5-year year U.S. Treasury instrument as opposed to a short-term T-Bill?

A. While a shorter term instrument, such as a 91-day T-Bill, presents the lowest possible total risk to an investor, a good argument can be made that the yield on an instrument that matches the investment period of the asset being analyzed in the CAPM model should be used as the risk-free rate of return. Since utilities in Arizona generally file for rates every three to five years, the yield on a 5-year U.S. Treasury Instrument closely matches the investment period or, in the case of regulated utilities, the period that new rates will be in effect.

...

Q. How did you calculate the market risk premium used in your CAPM analysis?

A. I used both a geometric and an arithmetic mean of the historical total returns on the S&P 500 index from 1926 to 2007 as the proxy for the market rate of return (r_m). For the risk-free portion of the risk premium component (r_f), I used the geometric mean of the total returns of long-term government bonds for the same eighty-one year period. The market risk premium (r_m - r_f) that results by using these inputs is 5.10 percent (10.40% - 5.30% = 5.10%). The market risk premium that results by using the arithmetic mean calculation is 6.80 percent (12.30% - 5.50% = 6.80%).

Q. How did you select the beta coefficients that were used in your CAPM analysis?

A. The beta coefficients (ß), for the individual utilities used in both my proxies, were calculated by Value Line and were current as of March 13, 2009. Value Line calculates its betas by using a regression analysis between weekly percentage changes in the market price of the security being analyzed and weekly percentage changes in the NYSE Composite Index over a five-year period. The betas are then adjusted by Value Line for their long-term tendency to converge toward 1.00. The beta coefficients for the LDC's included in my sample ranged from 0.60 to 0.75 with an average beta of 0.67.

Q. What are the results of your CAPM analysis?

A. As shown on pages 1 and 2 of Schedule WAR-7, my CAPM calculation using a geometric mean to calculate the risk premium results in an average expected return of 5.26 percent. My calculation using an arithmetic mean results in an average expected return of 6.39 percent.

Q. Please summarize the results derived under each of the methodologies presented in your testimony.

A. The following is a summary of the cost of equity capital derived under each methodology used:

METHOD	**RESULTS**
DCF	11.40%
CAPM	5.26% – 6.39%

Based on these results, my best estimate of an appropriate range for an original cost of equity capital for UNSG is 5.26 percent to 11.40 percent. My final recommended original cost of equity capital figure is 8.61 percent.

. . .

Q How did you arrive at your recommended original cost of equity capital figure of 8.61 percent?

A. My recommended original cost of equity capital figure of 8.61 percent is the average of my DCF and CAPM results. The calculation can be seen on Page 3 of Schedule WAR-1.

Q. How does your recommended original cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The 11.00 percent cost of equity capital proposed by the Company is 239 basis points higher than the 8.61 percent original cost of equity capital that I am recommending.

Current Economic Environment

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are also investing in non-regulated entities.

Q. Please discuss your analysis of the current economic environment.

A. My analysis includes a brief review of the economic events that have occurred since 1990. Schedule WAR-8 displays various economic indicators and other data that I will refer to during this portion of my testimony.

In 1991, as measured by the most recently revised annual change in gross domestic product ("GDP"), the U.S. economy experienced a rate of growth of negative 0.20 percent. This decline in GDP marked the beginning of a mild recession that ended sometime before the end of the first half of 1992. Reacting to this situation, the Federal Reserve Board ("Federal Reserve" or "Fed"), then chaired by noted economist Alan Greenspan, lowered its benchmark federal funds rate[12] in an effort to further loosen monetary constraints - an action that resulted in lower interest rates.

During this same period, the nation's major money center banks followed the Federal Reserve's lead and began lowering their interest rates as well. By the end of the fourth quarter of 1993, the prime rate (the rate charged by banks to their best customers) had dropped to 6.00 percent from a 1990 level of 10.01 percent. In addition, the Federal Reserve's discount

[12] This is the interest rate charged by banks with excess reserves at a Federal Reserve district bank to banks needing overnight loans to meet reserve requirements. The federal funds rate is the most sensitive indicator of the direction of interest rates, since it is set daily by the market, unlike the prime rate and the discount rate, which are periodically changed by banks and by the Federal Reserve Board, respectively.

rate on loans to its member banks had fallen to 3.00 percent and short-term interest rates had declined to levels that had not been seen since 1972.

Although GDP increased in 1992 and 1993, the Federal Reserve took steps to increase interest rates beginning in February of 1994, in order to keep inflation under control. By the end of 1995, the Federal discount rate had risen to 5.21 percent. Once again, the banking community followed the Federal Reserve's moves. The Fed's strategy, during this period, was to engineer a "soft landing." That is to say that the Federal Reserve wanted to foster a situation in which economic growth would be stabilized without incurring either a prolonged recession or runaway inflation.

Q. Did the Federal Reserve achieve its goals during this period?

A. Yes. The Fed's strategy of decreasing interest rates to stimulate the economy worked. The annual change in GDP began an upward trend in 1992. A change of 4.50 percent and 4.20 percent were recorded at the end of 1997 and 1998 respectively. Based on daily reports that were presented in the mainstream print and broadcast media during most of 1999, there appeared to be little doubt among both economists and the public at large that the U.S. was experiencing a period of robust economic growth highlighted by low rates of unemployment and inflation. Investors, who believed that technology stocks and Internet company start-ups (with little or no history of earnings) had high growth potential, purchased these types of issues with enthusiasm. These types of investors, who exhibited what former Chairman Greenspan described as "irrational exuberance," pushed stock prices and market indexes to all time highs from 1997 to 2000.

Q. What has been the state of the economy since 2001?

A. The U.S. economy entered into a recession near the end of the first quarter of 2001. The bullish trend, which had characterized the last half of the 1990's, had already run its course sometime during the third quarter of 2000. Economic data released since the beginning of 2001 had already been disappointing during the months preceding the September 11, 2001 terrorist attacks on the World Trade Center and the Pentagon. Slower growth figures, rising layoffs in the high technology manufacturing sector, and falling equity prices (due to lower earnings expectations) prompted the Fed to begin cutting interest rates as it had done in the early 1990's. The now infamous terrorist attacks on New York City and Washington D.C. marked a defining point in this economic slump and prompted the Federal Reserve to continue its rate cutting actions through December 2001. Prior to the 9/11 attacks, commentators, reporting in both the mainstream financial press and various economic publications including Value Line, believed that the Federal Reserve was cutting rates in the hope of avoiding a recession.

Despite several intervals during 2002 and 2003 in which the Federal Open Market Committee ("FOMC") decided not to change interest rates – moves which indicated that the worst may be over and that the recession might have bottomed out during the last quarter of 2001 – a lackluster economy persisted. The continuing economic malaise and even fears of possible deflation prompted the FOMC to make a thirteenth rate cut on June 25, 2003. The quarter point cut reduced the federal funds rate to 1.00 percent, the lowest level in forty-five years.

Even though some signs of economic strength, mainly attributed to consumer spending, began to crop up during the latter part of 2002 and into 2003, Chairman Greenspan appeared to be concerned with sharp declines in capital spending in the business sector.

During the latter part of 2003, the FOMC went on record as saying that it intended to leave interest rates low "for a considerable period." After its two-day meeting that ended on January 28, 2004, the FOMC announced "that with inflation 'quite low' and plenty of excess capacity in the economy, policy-makers 'can be patient in removing its policy accommodation.[13]"

[13] Wolk, Martin, "Fed holds interest rates steady," MSNBC, January 28, 2004.

Q. What actions has the Federal Reserve taken in terms of interest rates since the beginning of 2001?

A. As noted earlier, from January 2001 to June 2003 the Federal Reserve cut interest rates a total of thirteen times. During this period, the federal funds rate fell from 6.50 percent to 1.00 percent. The FOMC reversed this trend on June 29, 2004 and raised the federal funds rate 25 basis points to 1.25 percent. From June 29, 2004 to January 31, 2006, the FOMC raised the federal funds rate thirteen more times to a level of 4.50 percent.

The FOMC's January 31, 2006 meeting marked the final appearance of Alan Greenspan, who had presided over the rate setting body for a total of eighteen years. On that same day, Greenspan's successor, Ben Bernanke, the former chairman of the President's Council of Economic Advisers and a former Fed governor under Greenspan from 2002 to 2005, was confirmed by the U.S. Senate to be the new Federal Reserve chief.

As expected by Fed watchers, Chairman Bernanke picked up where his predecessor left off and increased the federal funds rate by 25 basis points during each of the next three FOMC meetings for a total of seventeen consecutive rate increases since June 2004, and raising the federal funds rate to a level of 5.25 percent. The Fed's rate increase campaign finally came to a halt at the FOMC meeting held on August 8, 2006, when the FOMC decided not to raise rates.

Q. What was the reaction in the financial community to the Fed's decision not to raise interest rates?

A. As in the past, banks followed the Fed's lead once again and held the prime rate to a level of 8.25 percent, or 300 basis points higher than the federal funds rate of 5.25 percent established on June 29, 2006.

Q. How did analysts view the Fed's actions between January 2001 and August 2006?

A. According to an article that appeared in the December 2, 2004 edition of The Wall Street Journal, the FOMC's decision to begin raising rates two years ago was viewed as a move to increase rates from emergency lows in order to avoid creating an inflation problem in the future as opposed to slowing down the strengthening economy.[14] In other words, the Fed was trying to head off inflation *before* it became a problem. During the period following the August 8, 2006 FOMC meeting, the Fed's decisions not to raise rates were viewed as a gamble that a slower U.S. economy would help to cap growing inflationary pressures.[15]

...

[14] McKinnon, John D. and Greg IP, "Fed Raises Rates by a Quarter Point," The Wall Street Journal, September 22, 2004.

[15] Ip, Greg, "Fed Holds Interest Rates Steady As Slowdown Outweighs Inflation," The Wall Street Journal Online Edition, August 8, 2006.

Q. Was the Fed attempting to engineer another "soft landing", as it did in the mid-nineties, by holding interest rates steady?

A. Yes, however, as pointed out in an August 2006 article in The Wall Street Journal by E.S. Browning, soft landings – like the one that the Fed managed to pull off during the 1994-95 time frame, in which a recession or a bear market were avoided – rarely happen[16]. Since it began increasing the federal funds rate in June 2004, the Fed had assured investors that it would increase rates at a "measured" pace. Many analysts and economists interpreted this language to mean that former Chairman Greenspan would be cautious in increasing interest rates too quickly in order to avoid what is considered to be one of the Fed's few blunders during Greenspan's tenure – a series of increases in 1994 that caught the financial markets by surprise after a long period of low rates. The rapid rise in rates contributed to the bankruptcy of Orange County, California and the Mexican peso crisis[17]. According to Mr. Browning, at the time that his article was published, the hope was that Chairman Bernanke would succeed in slowing the economy "just enough to prevent serious inflation, but not enough to choke off growth." In other words, "a 'Goldilocks economy,' in which growth is not too hot and not too cold."

[16] Browning, E.S, "Not Too Fast, Not Too Slow…," The Wall Street Journal Online Edition, August 21, 2006.

[17] Associated Press (AP), "Fed begins debating interest rates" USA Today, June 29, 2004.

Q. Was the Fed's attempt to engineer a soft landing successful during the period that followed the August 8, 2006 FOMC meeting?

A. It would appear so. Articles published in the mainstream financial press were generally upbeat on the economy during that period. An example of this is an article written by Nell Henderson that appeared in the January 30, 2007 edition of The Washington Post. According to Ms. Henderson, "a year into [Fed Chairman] Bernanke's tenure, the [economic] picture has turned considerably brighter. Inflation is falling; unemployment is low; wages are rising; and the economy, despite continued problems in housing, is growing at a brisk clip."[18]

Q. What has been the state of the economy over the past two years?

A. Reports in the mainstream financial press during the majority of 2007 reflected the view that the U.S. economy was slowing as a result of a worsening situation in the housing market and higher oil prices. The overall outlook for the economy was one of only moderate growth at best. Also during this period the Fed's key measure of inflation began to exceed the rate setting body's comfort level.

On August 7, 2007, the FOMC decided not to increase or decrease the federal funds rate for the ninth straight time and left its target rate

[18] Henderson, Nell, "Bullish on Bernanke" The Washington Post, January 30, 2007.

unchanged at 5.25 percent.[19] At the time of the Fed's decision, analysts speculated that a rate cut over the next several months was unlikely given the Fed's concern that inflation would fail to moderate. However, during this same period, evidence of an even slower economy and a possible recession was beginning to surface. Within days of the Fed's decision to stand pat on rates, a borrowing crisis rooted in a deterioration of the market for subprime mortgages and securities linked to them, forced the Fed to inject $24 billion in funds (raised through open market operations) into the credit markets.[20] By Friday, August 17, 2007, after a turbulent week on Wall Street, the Fed made the decision to lower its discount rate (i.e. the rate charged on direct loans to banks) by 50 basis points, from 6.25 percent to 5.75 percent, and took steps to encourage banks to borrow from the Fed's discount window in order to provide liquidity to lenders. According to an article that appeared in the August 18, 2007 edition of The Wall Street Journal,[21] the Fed had used all of its tools to restore normalcy to the financial markets. If the markets failed to settle down, the Fed's only weapon left was to cut the Federal Funds rate – possibly before the next FOMC meeting scheduled on September 18, 2007.

[19] Ip, Greg, "Markets Gyrate As Fed Straddles Inflation, Growth" The Wall Street Journal, August 8, 2007

[20] Ip, Greg, "Fed Enters Market To Tamp Down Rate" The Wall Street Journal, August 9, 2007

[21] Ip, Greg, Robin Sidel and Randall Smith, "Fed Offers Banks Loans Amid Crises" The Wall Street Journal, August 9, 2007

Q. Did the Fed cut rates as a result of the subprime mortgage borrowing crises?

A. Yes. At its regularly scheduled meeting on September 18, 2007, the FOMC surprised the investment community and cut both the federal funds rate and the discount rate by 50 basis points (25 basis points more than what was anticipated). This brought the federal funds rate down to a level of 4.75 percent. The Fed's action was seen as an effort to curb the aforementioned slowdown in the economy. Over the course of the next four months, the FOMC reduced the Federal funds rate by a total 175 basis points to a level of 3.00 percent – mainly as a result of concerns that the economy was slipping into a recession. This included a 75 basis point reduction that occurred one week prior to the FOMC's meeting on January 29, 2008.

Q. What actions has the Fed taken in regard to interest rates over the past year?

A. The Fed made two more rate cuts which included a 75 basis point reduction in the federal funds rate on March 18, 2008 and an additional 25 basis point reduction on April 30, 2008. The Fed's decision to cut rates was based on its belief that the slowing economy was a greater concern than the current rate of inflation (which the majority of FOMC members believed would moderate during the economic slowdown).[22] As a result of the Fed's actions, the federal funds rate was reduced to a level of 2.00 percent. From April 30, 2008 through September 16, 2008, the Fed took no further action on its key interest rate. However, the days before and after the Fed's September 16, 2008 meeting saw longstanding Wall Street firms such as Lehman Brothers, Merrill Lynch and AIG failing as a result of their subprime holdings. By the end of the week, the Bush administration had announced plans to deal with the deteriorating financial condition which had now become a worldwide crisis. The administrations actions included former Treasury Secretary Henry Paulson's request to Congress for $700 billion to buy distressed assets as part of a plan to halt what has been described as the worst financial crisis since the 1930's[23]. Amidst this turmoil, the Fed made the decision to cut the federal funds rate by another 50 basis points in a coordinated move with foreign central banks on October 8, 2008. This was followed by another 50 basis point cut during the regular FOMC meeting on October 29, 2008. At the time of this writing, the federal funds target rate now stands at 0.25 percent, the result of a 75 basis point cut announced on December 16, 2008. After FOMC meetings in January, March and April of 2009, the Fed elected not to make any changes in the federal funds rate, stating in January that the

[22] Ip, Greg, "Credit Worries Ease as Fed Cuts, Hints at More Relief" The Wall Street Journal, March 19, 2008

[23] Soloman, Deborah, Michael R. Crittenden and Damian Paletta, "U.S. Bailout Plan Calms Markets, But Struggle Looms Over Details" The Wall Street Journal, September 20, 2008

rate would remain low "for some time."[24] Presently, the Fed's discount rate is at 0.50 percent, a level not seen since 1940s.[25] Based on data released during the early part of December 2008, the U.S. is now officially in a recession which began in December of 2007.

Q. Putting this all into perspective, how have the Fed's actions since 2000 affected benchmark rates?

A. U.S. Treasury instruments are for the most part still at historically low levels. The Fed's actions have also had the overall effect of reducing the cost of many types of business and consumer loans. As can be seen in Schedule WAR-8, the previously mentioned federal discount rate (the rate charged to the Fed's member banks), has fallen to 0.50 percent from 2.25 percent in 2008.

Q. What has been the trend in other leading interest rates over the last year?

A. As of May 13, 2009, the leading interest rates have all dropped from the levels that existed a year ago (Attachment C, Value Line Selection & Opinion page 3529). The prime rate has fallen from 5.00 percent a year ago to 3.25 percent. The benchmark federal funds rate, just discussed, has decreased from 2.00 percent, in May 2008, to a level of 0.25 percent

[24] Hilsenrath, Jon and Liz Rappaport, "Fed Weighs Idea of Buying Treasurys as Focus Shifts" The Wall Street Journal, January 29, 2009

[25] Hilsenrath, Jon, "Fed Cuts Rates Near Zero to Battle Slump" The Wall Street Journal, December 17, 2008

(as a result of the December 16, 2008 rate cut discussed above). The yields on all of the non-inflation protected maturities of U.S. Treasury instruments exhibited in my Attachment C have also decreased over the past year. A previous trend, described by former Chairman Greenspan as a "conundrum"[26], in which long-term rates fell as short-term rates increased, thus creating a somewhat inverted yield curve that existed as late as June 2007, is completely reversed and a more traditional yield curve (one where yields increase as maturity dates lengthen) presently exists (Attachment C). The 5-year Treasury yield, used in my CAPM analysis, has fallen from 3.20 percent, in May 2008, to 1.98 percent as of May 13, 2009. The 30-Year Treasury constant maturity rate also decreased from 4.61 percent over the past year to 4.10 percent. These current yields are considerably lower than corresponding yields that existed during the early nineties and at the beginning of the current decade (as can be seen on Schedule WAR-8).

Q. What is the current outlook for the economy?

A. Value Line's analysts have become more optimistic in their outlook on the economy as of late and had this to say in their Quarterly Economic Review that appeared in the May 29, 2009 edition of Value Line's Selection and Opinion publication:

[26] Wolk, Martin, "Greenspan wrestling with rate 'conundrum'," MSNBC, June 8, 2005

> **We probably have seen the low point in the business cycle,** with the six month period from early last fall through late this winter likely having marked that trough. The business outlook, which deteriorated steadily during this time—with housing, auto demand, retail sales, manufacturing, and on manufacturing all slumping in tandem— has grown less troubling in recent weeks. The lessening in the recession's clout suggests that the U.S. gross domestic product, which fell 6.3% in the fourth quarter of 2008 and by 6.1% in the opening period of this year, will decline by less than half that amount in the quarter that ends on June 30th. It should be noted that the surveys being issued largely detail a reduction in the economic downturn's severity, rather than any appreciable pickup in strength. In our view, we are still months away from a sustained business upturn. The best that seems ahead in the next 12 to 18 months is an uneven and understated recovery, with quarterly growth only gradually rising above 2%. We think it will be late 2010 or early 2011 before the economy really gets rolling.

Q. What is Value Line's outlook for interest rates?

A. In the Selection and Opinion publication noted above, Value Line's analysts had this to say:

> **Interest Rates:** Late last year, with the threat of a deepening recession, or worse, increasing by the day, the Federal Reserve voted to lower the Federal Funds rate (the rate charged on overnight loans between banks) to near zero. That is where they remain now and are likely to stay for a year or more. Other short-term interest rates — notably on three-and six-month Treasury bills — remain negligible, as do yields on money market funds and bank certificates of deposit of short duration. Longer-term fixed-income instruments (i.e., 10-year Treasury notes and 30-year Treasury bonds), where yields are more closely tied to long-range inflationary expectations, are also low by recent standards, at 3.2% and 4.2%, respectively. Here, though, yields are trending higher, as some market forecasters opine that inflation will pose a problem later in the pending business recovery. Time will tell if such worries are justified. Long-term interest rates are not yet serious competition for stocks, but they could become so with even a moderate further increase.

Q. What is Value Line's opinion on the current rate of inflation?

A. Also in the Selection and Opinion publication noted above, Value Line's analysts had this to say:

> **Inflation:** The major story here has been the ratcheting down of inflation since late last year, when declining global economic activity and plunging oil prices helped bring about selective deflation, or falling prices. Producer (wholesale) and consumer prices fell further during the opening quarter of 2009, albeit less sharply than in the preceding three months, as demand for labor, raw materials, and energy all contracted. The threat of deflation now seems to be lessening, as the decline in economic activity slows. Our sense is that aggregate price changes will be limited in the second quarter of this year and that inflation will start to selectively edge higher by the fourth quarter. Somewhat higher producer and consumer prices are likely in 2010. We think it will be 2011 or 2012, before there is much chance of an inflation problem.

Q. How are natural gas utilities faring in the current economic environment?

A. Natural gas utilities appear to be doing well and represent a safe investment according to Value Line analyst Richard Gallagher. In the March 13, 2009 quarterly update on the natural gas industry Mr. Gallagher stated the following:

> The Natural Gas Utility Industry has performed well in recent months. This is impressive given the weak economy and a tough regulatory environment. Despite these challenges, companies in this sector continue to deliver solid results and represent a relatively safe option amid the turmoil in the world's financial markets. As a result, this group has risen near the top of our industry spectrum.

Mr. Gallagher went on to state:

> The global economy continues to struggle. Tight credit and a slumping real estate market are among the main factors contributing to the recessionary environment. Furthermore, these conditions continue to weigh on results in this sector. Indeed, usage continues to decline as customers have become more cost conscious. Moreover, bill collection has become increasingly difficult as unemployment and foreclosures continue to rise. Despite the aforementioned conditions, investors should note that this group is an interesting defensive play. While these factors will likely continue to impact the utilities, this industry should perform well compared to the rest of the market in the months ahead. Natural Gas Utilities generally have solid balance sheets and predictable cash flows, which is appealing given the weakness in the economy.

Mr. Gallagher concluded:

> The Natural Gas Utility sector has climbed near the top of our industry spectrum in recent months. Indeed, it features numerous timely stocks. In fact, UGI holds our highest rank (1) for Timeliness. However, various other companies are ranked to outperform the market over the coming six to 12 months. What's more, the majority of the equities in this industry offer above-average yields. Most notably, Nicor, AGL Resources and Atmos Energy all offer attractive payouts supported by steady cash flows. Therefore, investors looking for a good play in the year ahead should consider some of the names in this group.

Q. After weighing the economic information that you've just discussed, do you believe that the cost of equity that you have estimated is reasonable for UNSG?

A. I believe that my recommended cost of equity will provide UNSG with a reasonable rate of return on the Company's invested capital when economic data on interest rates (that are still low by historical standards) and a low and stable outlook for inflation are all taken into consideration. As I noted earlier, the Hope decision determined that a utility is entitled to earn a rate of return that is commensurate with the returns it would make on other investments with comparable risk. I believe that my DCF analysis has produced such a return.

COST OF DEBT

Q. Have you reviewed UNSG's testimony on the Company-proposed cost of long-term debt?

A. Yes, I have reviewed the testimony prepared by Mr. Grant.

Q. Do you agree with Mr. Grant's inclusion of the amortized debt discount and expenses and losses attributed to reacquired debt and the credit facility fees to arrive at his final cost of debt figure of 6.49 percent?

A. Yes.

Q. What cost of long-term debt are you recommending for UNSG?

A. I am recommending that the Commission adopt the Company proposed cost of debt of 6.49 percent.

CAPITAL STRUCTURE

Q. Have you reviewed UNSG's testimony regarding the Company's proposed capital structure?

A. Yes.

Q. Please describe the Company's proposed capital structure.

A. The Company is proposing that the Commission adopt the Company's actual test year capital structure comprised of 50.01 percent long-term debt and 49.99 percent common equity.

Q. What capital structure are you proposing for UNSG?

A. I am also recommending that the Commission adopt the Company's actual test year capital structure comprised of 50.01 percent long-term debt and 49.99 percent common equity.

Q. Is UNSG's actual capital structure in line with industry averages?

A. For the most part yes. UNSG's actual test year capital structure is very close to the capital structures of the LDC's included in my cost of capital analysis. As can be seen in Schedule WAR-9, the capital structures for those utilities averaged approximately 46 percent for debt and 54 percent for equity (53.4 percent common equity + 0.7 percent preferred equity).

WEIGHTED COST OF CAPITAL

Q. How does the Company's proposed weighted average cost of capital compare with your recommendation?

A. The Company has proposed an unadjusted weighted average cost of capital of 8.75 percent. This composite figure is the result of a weighted average of UNSG's proposed 6.49 percent cost of long-term debt and 11.00 percent cost of common equity. The Company-proposed 8.75 percent OCRB weighted cost of capital is 120 basis points higher than the 7.55 percent OCRB weighted cost that I am recommending which is the weighted cost of my recommended 6.49 percent cost of long-term debt and my recommended 8.61 percent cost of common equity. In its Application, the Company makes a 79 basis point upward adjustment to the aforementioned 8.75 percent weighted average cost of capital in order to arrive at a 9.54 percent OCROR that produces the same level of operating income as the Company-proposed 6.80 percent FVROR does.

Q. How does the Company's proposed FVROR of 6.80 percent compare with RUCO's recommendation?

A. The Company has proposed a FVROR of 6.80 percent which is 142 basis points higher than the 5.38 percent FVROR that RUCO is recommending.

Q. Why is RUCO recommending a FVROR that is lower than the OCROR that was derived from the results of your DCF and CAPM analyses?

A. As I explained earlier in my testimony, the lower FVROR removes an inflation expectation that is embedded in the OCROR. The method that RUCO has relied on to arrive at its recommended 5.38 percent FVROR is consistent with the provisions contained in Decision No. 70441 which established a FVROR for Chaparral City Water Company ("Remand Proceeding"). During the Remand Proceeding, the Commission was required to develop an appropriate rate of return on Chaparral's FVRB under a remand order from the Arizona Court of Appeals. In doing so, the Commission adopted, in part, a methodology that was proposed by Ben Johnson, Ph.D., an expert witness who testified on behalf of RUCO on the FVRB rate of return issue that was central to that proceeding.[27]

[27] On September 30, 2005, the Commission issued Decision No. 68176 which granted a permanent rate increase to Chaparral. Following the Commission's decision on the matter, the Company filed an application for rehearing on which the Commission took no action. Chaparral subsequently filed an appeal with the Arizona Court of Appeals, Division One ("Court of Appeals"). The Company's appeal claimed that Chaparral was denied a fair rate of return on its invested capital as a result of the Commission's established method of calculating a level of operating income based on the Company's fair value rate base ("FVRB"). On February 13, 2007, the Court of Appeals issued a Memorandum Decision which affirmed in part, vacated, and remanded Decision No. 68176 to the Commission for further determination.

Q. What did Dr. Johnson recommend in the Remand Proceeding?

A. Dr. Johnson recommended that a 200 basis point adjustment be made to the original weighted average cost of capital in order to remove the effects of general inflation from Chaparrals FVRRB. His recommendation was based on the low end of a range of figures that represented the difference between Treasury Inflation-Protected Securities ("TIPS") and U.S. Treasury bonds with similar liquidity and maturity characteristics.

Q. Did the Commission adopt Dr. Johnson's recommendation?

A. In part, yes. The Commission adopted a FVROR that was derived from a an inflation adjustment that reduced the cost of common equity by 200 basis points as opposed Dr. Johnson's recommendation to reduce the original weighted average cost of capital by 200 basis points.

Q. Have you calculated a similar inflation adjustment in this case?

A. Yes.

Q. How did you calculate your inflation adjustment?

A. I relied on the same data sets of information that Dr. Johnson used to develop his inflation factor adjustment during the Remand Proceeding (Schedule WAR-1, Page 4 of 4). Since there was virtually no change in the average of the data – which compared TIP's and U.S. Treasury bonds with similar liquidity and maturity characteristics, I am recommending that a 250 basis point adjustment be used to arrive at an appropriate FVROR for UNSG .

COMMENTS ON UNSG'S COST OF EQUITY CAPITAL TESTIMONY

Q. What methods did Mr. Grant use to arrive at his cost of common equity for UNSG?

A. Mr. Grant used a DCF methodology and a CAPM methodology to estimate UNSG's cost of common equity. He also relied on a bond yield plus risk premium approach.

Q. Can you provide a comparison of the results derived from your respective DCF and CAPM models?

A. Yes.

DCF Comparison

Q. Were there any differences in the way that you conducted your DCF analysis and the way that Mr. Grant conducted his?

A. Yes, Mr. Grant relied on the results of a multi-stage DCF model, using the proxy of ten LDC's that I described earlier in my testimony, as opposed to the single-stage constant growth model that I relied on. Mr. Grant stated that his decision to rely solely on the multi-stage model was based on his belief that the single-stage constant growth model cannot be applied to companies having expected near-term growth rates that are significantly higher or lower than their long-term growth potential.

Q. Do you agree with Mr. Grant's rationale for not relying on the single-stage DCF model?

A. No. The long-term growth rate that Mr. Grant uses in the second stage of his multi-stage DCF model is a 6.30 percent figure that is the sum of a 3.40 percent average of real economic growth from 1929 through 2007, and 2.90 percent expected rate of inflation. The use of such a growth estimate assumes that the long-term growth rate for the natural gas utilities in his sample will be a combination of analysts' long-term growth rate projections and the growth rate of all goods and services produced by labor and property in the U.S. adjusted for inflation. A good argument can be made that more emphasis should be placed on the near-term component of Mr. Grant's multi-stage DCF model as opposed to the long-term growth rate that is carried out into perpetuity.

Q. Why didn't you conduct a multi-stage DCF analysis like the one conducted by Mr. Grant?

A. Primarily because the growth rate component that I estimated for my single-stage model already takes into consideration both a near-term and a 5-year long-term growth rate projection that are specific to the LDC's included in my proxy. As with the use of a 5-year treasury instrument for the risk free rate of return in my CAPM model, this 5-year investment horizon is very close to the 3 to 5-year periods that utilities in Arizona apply for rate relief.

Q. What is the difference between Mr. Grant's DCF estimate and your DCF estimate?

A. Mr. Grant's DCF high and low estimates, derived from his multi-stage model, of 9.50 percent and 11.20 percent are 190 to 20 basis points lower than the 11.40 percent cost of common equity derived from my DCF analysis which is a mean average of the DCF estimates of the ten LDC's in my proxy.

Q. Does Mr. Grant provide an estimate that is based on the single-stage model that you employed?

A. Not directly, however the exhibits contained in his testimony contain inputs and estimates used in his multi-stage model that can also be used in the single-stage model. Using the inputs and estimates that appear in Mr. Grant's exhibits, a single-stage model would produce a mean average estimate of 9.17 percent or 223 basis points lower than my 11.40 percent estimate. Using Mr. Grant's same 5-year DCF growth estimates for each of the LDC's in our sample, and substituting his dividend and stock price inputs with more recent data that I relied on, produces a mean average estimate of 10.18 percent which is 122 basis points lower than my single-stage DCF estimate.

Q. Have there been any changes in closing stock prices since Mr. Grant filed his direct testimony?

A. Yes. The stock prices for the LDC's used in our proxies have fallen since Mr. Grant filed his direct testimony, thus producing higher dividend yields. The difference between the average closing stock prices used in my analysis and Mr. Grant's analysis are as follows:

	Rigsby	Grant	Difference
AGL	$28.35	$32.85	-$4.50
ATO	$23.79	$26.75	-$2.96
LG	$34.89	$44.93	-$10.04
NJR	$32.51	$34.96	-$2.45
GAS	$32.52	$43.60	-$11.08
NWN	$41.80	$46.95	-$5.15
PNY	$24.50	$28.07	-$3.57
SJI	$34.87	$34.91	-$0.04
SWX	$20.23	$29.26	-$9.03
WGL	$30.85	$32.74	-$1.89

...

The differences in our respective dividend yields are as follows:

	Rigsby	Grant	Basis Point Difference
AGL	6.07%	5.27%	80
ATO	5.55%	5.08%	46
LG	4.41%	3.45%	96
NJR	3.81%	3.32%	50
GAS	5.72%	4.27%	145
NWN	3.78%	3.39%	39
PNY	4.42%	3.81%	43
SJI	6.51%	3.24%	327
SWX	4.70%	3.18%	152
WGL	4.67%	4.43%	24

Based on this information it is fair to say that a single stage model using updated stock prices, while holding Mr. Grant's other DCF growth component estimates constant, would produce a lower single-stage DCF estimate than the one that I have calculated.

CAPM Comparison

Q. Please describe the differences in the way that you conducted your CAPM analysis and the way that Mr. Grant conducted his?

A. The main difference between Mr. Grant's CAPM analysis and mine is that he relied solely on an arithmetic mean of the historical returns on the S&P 500 index from 1926 to 2007 as the proxy for the market rate of return (i.e. r_m) in order to arrive at his market risk premium (i.e. r_m - r_f) in his CAPM model. His 7.10 percent market risk premium, based on an arithmetic mean, is 30 basis points higher than the 6.80 percent market risk premium which I obtained from Morningstar data.

Q. What financial instrument did Mr. Grant use as a proxy for the risk free (i.e. r_f) rate in his CAPM model?

A. Mr. Grant used the yield to maturity on a 20-year U.S. Treasury instrument, which was 4.53 percent around the time that his direct testimony was filed in November 2008.

Q. What is the current yield on a 20-year U.S. Treasury bond?

A. As of the week ended May 22, 2007 the yield on a 20-year U.S. Treasury bond was 4.22 percent.

...

Q. Do you agree with Mr. Grant's use of a 20-year Treasury rate as the risk free proxy in the CAPM model?

A. No. As I stated earlier in my testimony, I believe that a 5-year instrument is more appropriate given the fact that utility rates are generally in effect for a 3 to 5-tear time frame.

Q. Did Mr. Grant use the same Value Line betas that you used in your CAPM analysis?

A. Yes. However Value Line's betas for the LDC's in our proxies have decreased since Mr. Grant filed his direct testimony. The mean average of the Value Line betas used by Mr. Grant is 0.87 as opposed to my average beta of 0.67, which was current as of March 13, 2009.

Q. What is the difference between Mr. Grant's CAPM estimate and your CAPM estimate?

A. Mr. Grant's CAPM estimate, derived from his arithmetic mean model, of 10.70 percent is 431 basis points higher than the 6.39 percent cost of common equity derived from my arithmetic mean CAPM analysis and 544 basis points higher than my 5.26 percent cost of common equity derived from my geometric mean CAPM analysis. Updating Mr. Grant's risk free rate of return and beta inputs in his CAPM model would produce an expected return of 8.98, which is 172 basis points lower than the 10.70 percent figure presented in his testimony.

Final Cost of Equity Estimate

Q. How did Mr. Grant arrive at his proposed 11.00 percent cost of common equity for UNSG?

A. Mr. Grant used his own judgment to arrive at his proposed 11.00 percent cost of equity capital which is based on the results of his DCF, CAPM and risk premium analyses. He also compared UNSG's credit rating with the bond ratings of A-rated and Baa-rated utilities.

Q. How did Mr. Grant arrive at his proposed 6.80 percent fair value rate of return?

A. Mr. Grant again relied on his own judgment and stated that the 6.80 percent fair value rate of return was lower than the results he obtained by using the method that I relied on, which was adopted in Decision No. 70441 (and another method proposed by ACC Staff), and would produce an operating income of $256 million. According to Mr. Grant, this is the level of income needed to provide UNSG's with the ability to earn its cost of capital, maintain creditworthiness and attract capital.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Mr. Grant or any other witness for UNSG constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on UNSG?

A. Yes, it does.

Qualifications of William A. Rigsby, CRRA

EDUCATION:

University of Phoenix
Master of Business Administration, Emphasis in Accounting, 1993

Arizona State University
College of Business
Bachelor of Science, Finance, 1990

Mesa Community College
Associate of Applied Science, Banking and Finance, 1986

Society of Utility and Regulatory Financial Analysts
38th Annual Financial Forum and CRRA Examination
Georgetown University Conference Center, Washington D.C.
Awarded the Certified Rate of Return Analyst designation
after successfully completing SURFA's CRRA examination.

Michigan State University
Institute of Public Utilities
N.A.R.U.C. Annual Regulatory Studies Program, 1997 &1999

Florida State University
Center for Professional Development & Public Service
N.A.R.U.C. Annual Western Utility Rate School, 1996

EXPERIENCE:

Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona
April 2001 – Present

Senior Rate Analyst
Accounting & Rates - Financial Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
July 1999 – April 2001

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona
December 1997 – July 1999

Utilities Auditor II and III
Accounting & Rates – Revenue Requirements Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
October 1994 – November 1997

Tax Examiner Technician I / Revenue Auditor II
Arizona Department of Revenue
Transaction Privilege / Corporate Income Tax Audit Units
Phoenix, Arizona
July 1991 – October 1994

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Type of Proceeding
ICR Water Users Association	U-2824-94-389	Original CC&N
Rincon Water Company	U-1723-95-122	Rate Increase
Ash Fork Development Association, Inc.	E-1004-95-124	Rate Increase
Parker Lakeview Estates Homeowners Association, Inc.	U-1853-95-328	Rate Increase
Mirabell Water Company, Inc.	U-2368-95-449	Rate Increase
Bonita Creek Land and Homeowner's Association	U-2195-95-494	Rate Increase
Pineview Land & Water Company	U-1676-96-161	Rate Increase
Pineview Land & Water Company	U-1676-96-352	Financing
Montezuma Estates Property Owners Association	U-2064-96-465	Rate Increase
Houghland Water Company	U-2338-96-603 et al	Rate Increase
Sunrise Vistas Utilities Company – Water Division	U-2625-97-074	Rate Increase
Sunrise Vistas Utilities Company – Sewer Division	U-2625-97-075	Rate Increase
Holiday Enterprises, Inc. dba Holiday Water Company	U-1896-97-302	Rate Increase
Gardener Water Company	U-2373-97-499	Rate Increase
Cienega Water Company	W-2034-97-473	Rate Increase
Rincon Water Company	W-1723-97-414	Financing/Auth. To Issue Stock
Vail Water Company	W-01651A-97-0539 et al	Rate Increase
Bermuda Water Company, Inc.	W-01812A-98-0390	Rate Increase
Bella Vista Water Company	W-02465A-98-0458	Rate Increase
Pima Utility Company	SW-02199A-98-0578	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Pineview Water Company	W-01676A-99-0261	WIFA Financing
I.M. Water Company, Inc.	W-02191A-99-0415	Financing
Marana Water Service, Inc.	W-01493A-99-0398	WIFA Financing
Tonto Hills Utility Company	W-02483A-99-0558	WIFA Financing
New Life Trust, Inc. dba Dateland Utilities	W-03537A-99-0530	Financing
GTE California, Inc.	T-01954B-99-0511	Sale of Assets
Citizens Utilities Rural Company, Inc.	T-01846B-99-0511	Sale of Assets
MCO Properties, Inc.	W-02113A-00-0233	Reorganization
American States Water Company	W-02113A-00-0233	Reorganization
Arizona-American Water Company	W-01303A-00-0327	Financing
Arizona Electric Power Cooperative	E-01773A-00-0227	Financing
360networks (USA) Inc.	T-03777A-00-0575	Financing
Beardsley Water Company, Inc.	W-02074A-00-0482	WIFA Financing
Mirabell Water Company	W-02368A-00-0461	WIFA Financing
Rio Verde Utilities, Inc.	WS-02156A-00-0321 et al	Rate Increase/ Financing
Arizona Water Company	W-01445A-00-0749	Financing
Loma Linda Estates, Inc.	W-02211A-00-0975	Rate Increase
Arizona Water Company	W-01445A-00-0962	Rate Increase
Mountain Pass Utility Company	SW-03841A-01-0166	Financing
Picacho Sewer Company	SW-03709A-01-0165	Financing
Picacho Water Company	W-03528A-01-0169	Financing
Ridgeview Utility Company	W-03861A-01-0167	Financing
Green Valley Water Company	W-02025A-01-0559	Rate Increase
Bella Vista Water Company	W-02465A-01-0776	Rate Increase
Arizona Water Company	W-01445A-02-0619	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Arizona-American Water Company	W-01303A-02-0867 et al.	Rate Increase
Arizona Public Service Company	E-01345A-03-0437	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-03-0434	Rate Increase
Qwest Corporation	T-01051B-03-0454	Renewed Price Cap
Chaparral City Water Company	W-02113A-04-0616	Rate Increase
Arizona Water Company	W-01445A-04-0650	Rate Increase
Tucson Electric Power	E-01933A-04-0408	Rate Review
Southwest Gas Corporation	G-01551A-04-0876	Rate Increase
Arizona-American Water Company	W-01303A-05-0405	Rate Increase
Black Mountain Sewer Corporation	SW-02361A-05-0657	Rate Increase
Far West Water & Sewer Company	WS-03478A-05-0801	Rate Increase
Gold Canyon Sewer Company	SW-02519A-06-0015	Rate Increase
Arizona Public Service Company	E-01345A-05-0816	Rate Increase
Arizona-American Water Company	W-01303A-06-0014	Rate Increase
Arizona-American Water Company	W-01303A-05-0718	Transaction Approval
Arizona-American Water Company	W-01303A-05-0405	ACRM Filing
UNS Gas, Inc.	G-04204A-06-0463	Rate Increase
Arizona-American Water Company	W-01303A-07-0209	Rate Increase
Tucson Electric Power	E-01933A-07-0402	Rate Increase
Southwest Gas Corporation	G-01551A-07-0504	Rate Increase
Chaparral City Water Company	W-02113A-07-0551	Rate Increase
Arizona-American Water Company	W-01303A-08-0227 et al.	Rate Increase
Far West Water & Sewer Company	WS-03478A-08-0608	Interim Rate Increase
Johnson Utilities, LLC	WS-02987A-08-0180	Rate Increase

ATTACHMENT A

INDUSTRY TIMELINESS: 5 (of 99)

The Natural Gas Utility Industry has performed well in recent months. This is impressive given the weak economy and a tough regulatory environment. Despite these challenges, companies in this sector continue to deliver solid results and represent a relatively safe option amid the turmoil in the world's financial markets. As a result, this group has risen near the top of our industry spectrum.

Economic Environment

The global economy continues to struggle. Tight credit and a slumping real estate market are among the main factors contributing to the recessionary environment. Furthermore, these conditions continue to weigh on results in this sector. Indeed, usage continues to decline as customers have become more cost conscious. Moreover, bill collection has become increasingly difficult as unemployment and foreclosures continue to rise. Despite the aforementioned conditions, investors should note that this group is an interesting defensive play. While these factors will likely continue to impact the utilities, this industry should perform well compared to the rest of the market in the months ahead. Natural Gas Utilities generally have solid balance sheets and predictable cash flows, which is appealing given the weakness in the economy.

Regulation

This group is regulated by state commissions that dictate the return on equity these utilities can achieve. Consequently, the regulatory environment has a heavy bearing on each individual company's results. If a utility does not have ample relief, its budget can become strained. As a result, a company's infrastructure can age and profitability can decline. On the other hand, a favorable ruling can position a utility to register steady gains and allow it to build its infrastructure. Therefore, rate cases remain the main theme in this sector. On point, numerous companies currently have rate cases pending. *Southwest Gas, Nicor, AGL Resources* are all awaiting decisions, which should drive their performance going forward. Moreover, energy efficiency will likely become an increasingly important factor in these decisions given the new administration in the White House. As the United States moves in this direction, utilities that embrace energy conservation measures may benefit from a more favorable regulatory environment.

Nonregulated Ventures

A strategy that is becoming increasingly common is nonregulated ventures. These opportunities allow companies to diversify their operations and gain income that is not subject to the state regulatory commissions. These businesses currently make up only a small portion of this sector's profits but will likely become a more important opportunity in the years ahead.

Weather

The peak heating season is just about coming to an end. This period is when these utilities have their best opportunity to post strong results on the bottom line. Looking ahead, these companies will likely turn their attention to strengthening their operations and better managing their costs as we move toward the summer months.

Weather abnormalities can hurt results. Many of these businesses have weather-adjusted rate mechanisms that are used to hedge the risk of unseasonable weather. Thus, investors should keep an eye out for utilities that rely on this strategy since they usually have a relatively steady performance.

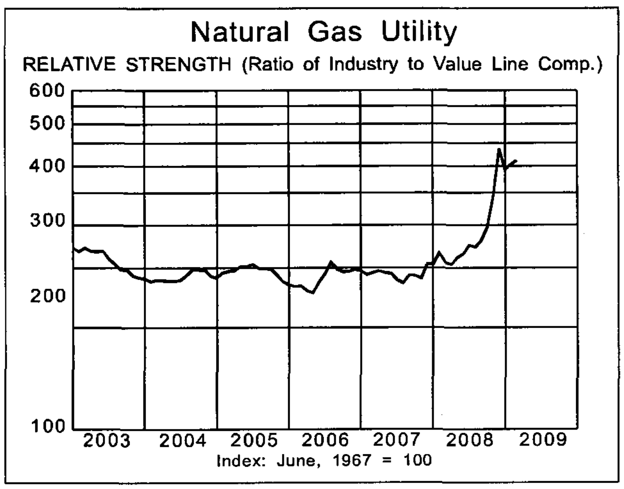
Conclusion

The Natural Gas Utility sector has climbed near the top of our industry spectrum in recent months. Indeed, it features numerous timely stocks. In fact, *UGI* holds our highest rank (1) for Timeliness. However, various other companies are ranked to outperform the market over the coming six to 12 months. What's more, the majority of the equities in this industry offer above-average yields. Most notably, *Nicor, AGL Resources* and *Atmos Energy* all offer attractive payouts supported by steady cash flows. Therefore, investors looking for a good play in the year ahead should consider some of the names in this group.

Richard Gallagher

Composite Statistics: Natural Gas Utility

2005	2006	2007	2008	2009	2010		12-14
36075	38273	38528	*40000*	*41500*	*42750*	Revenues ($mill)	*51250*
1386.0	1553.3	1562.4	*1650*	*1725*	*1800*	Net Profit ($mill)	*2150*
36.0%	35.3%	33.9%	*36.0%*	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
3.8%	4.0%	4.1%	*4.1%*	*4.2%*	*4.2%*	Net Profit Margin	*4.2%*
51.3%	51.2%	50.4%	*51.0%*	*51.0%*	*51.0%*	Long-Term Debt Ratio	*52.0%*
48.4%	48.7%	49.5%	*48.0%*	*48.0%*	*48.0%*	Common Equity Ratio	*46.0%*
29218	30847	32263	*33750*	*33250*	*34750*	Total Capital ($mill)	*40000*
30894	32543	33936	*35250*	*36750*	*38500*	Net Plant ($mill)	*46250*
6.5%	6.6%	6.5%	*6.5%*	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
9.7%	10.2%	9.8%	*10.0%*	*10.0%*	*10.5%*	Return on Shr. Equity	*11.0%*
9.8%	10.2%	9.8%	*10.0%*	*10.0%*	*10.5%*	Return on Com Equity	*11.0%*
3.5%	4.0%	3.7%	*4.0%*	*4.0%*	*4.5%*	Retained to Com Eq	*5.0%*
65%	61%	62%	*63%*	*63%*	*64%*	All Div'ds to Net Prof	*65%*
17.1	15.6	16.6		*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*13.0*
.91	.84	.88				Relative P/E Ratio	*.85*
3.8%	3.9%	3.7%				Avg Ann'l Div'd Yield	*4.6%*
315%	327%	336%	*350%*	*375%*	*375%*	Fixed Charge Coverage	*400%*



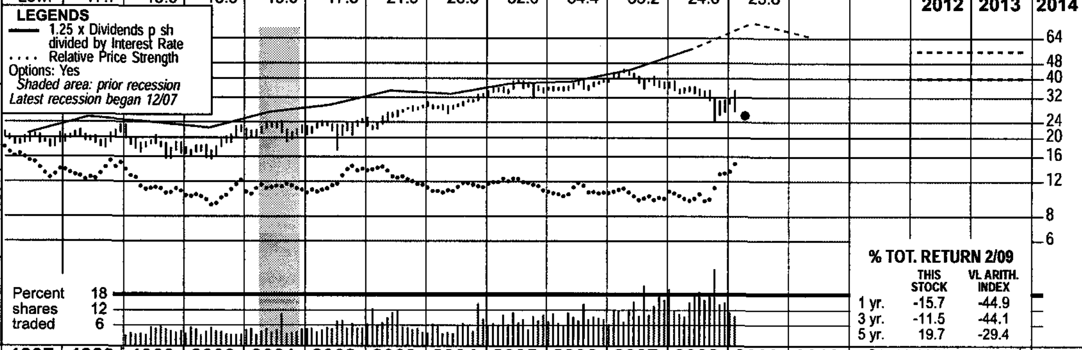
AGL RESOURCES NYSE-AGL

RECENT PRICE	25.92	P/E RATIO	9.2 (Trailing: 9.2; Median: 14.0)	RELATIVE P/E RATIO	0.89	DIV'D YLD	6.7%	VALUE LINE

TIMELINESS 2 Raised 2/13/09
SAFETY 2 New 7/27/90
TECHNICAL 2 Raised 3/6/09
BETA .75 (1.00 = Market)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	23.4	23.4	23.2	24.5	25.0	29.3	33.7	39.3	40.1	44.7	39.1	34.9
Low:	17.7	15.6	15.5	19.0	17.3	21.9	26.5	32.0	34.4	35.2	24.0	25.8

Target Price Range 2012 | 2013 | 2014



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+110%)	24%
Low	40	(+55%)	16%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	3	0	0	1	0	0	2	1
to Sell	0	2	0	0	1	0	0	3	1

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	105	131	92
to Sell	127	106	130
Hld's(000)	47696	46762	48796

Percent shares traded 18 12 6

% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-15.7	-44.9
3 yr.	-11.5	-44.1
5 yr.	19.7	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
22.73	23.59	19.32	21.91	22.75	23.36	18.71	11.25	19.04	15.32	15.25	23.89	34.98	33.73	32.64	36.41	**35.90**	**36.40**	Revenues per sh A	**39.40**
2.25	2.24	2.33	2.49	2.42	2.65	2.29	2.86	3.31	3.39	3.47	3.29	4.20	4.50	4.65	4.68	**4.70**	**4.85**	"Cash Flow" per sh	**5.30**
1.08	1.17	1.33	1.37	1.37	1.41	.91	1.29	1.50	1.82	2.08	2.28	2.48	2.72	2.72	2.71	**2.70**	**2.85**	Earnings per sh A B	**3.20**
1.04	1.04	1.04	1.06	1.08	1.08	1.08	1.08	1.08	1.08	1.11	1.15	1.30	1.48	1.64	1.68	**1.72**	**1.76**	Div'ds Decl'd per sh C■	**1.88**
2.49	2.37	2.17	2.37	2.59	2.05	2.51	2.92	2.83	3.30	2.46	3.44	3.44	3.26	3.39	4.84	**4.35**	**4.30**	Cap'l Spending per sh	**5.00**
9.90	10.19	10.12	10.56	10.99	11.42	11.59	11.50	12.19	12.52	14.66	18.06	19.29	20.71	21.74	21.48	**21.55**	**21.85**	Book Value per sh D	**21.75**
49.72	50.86	55.02	55.70	56.60	57.30	57.10	54.00	55.10	56.70	64.50	76.70	77.70	77.70	76.40	76.90	**78.00**	**79.00**	Common Shs Outst'g E	**85.00**
17.9	15.1	12.6	13.8	14.7	13.9	21.4	13.6	14.6	12.5	12.5	13.1	14.3	13.5	14.7	12.3	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**15.0**
1.06	.99	.84	.86	.85	.72	1.22	.88	.75	.68	.71	.69	.76	.73	.78	.76	*estimates*		Relative P/E Ratio	**1.00**
5.4%	5.9%	6.2%	5.6%	5.4%	5.5%	5.5%	6.2%	4.9%	4.7%	4.3%	3.9%	3.7%	4.0%	4.1%	5.0%			Avg Ann'l Div'd Yield	**3.9%**

CAPITAL STRUCTURE as of 12/31/08
Total Debt $2541.0 mill. **Due in 5 Yrs** $1410 mill.
LT Debt $1675.0 mill. **LT Interest** $80.0 mill.
(Total interest coverage: 4.0x)

Leases, Uncapitalized Annual rentals $30.0 mill.
Pension Assets-12/08 $242.0 mill. **Oblig.** $442.0 mill.

Pfd Stock None

Common Stock 76,902,777 shs.
as of 1/30/09
MARKET CAP: $2.0 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
1068.6	607.4	1049.3	868.9	983.7	1832.0	2718.0	2621.0	2494.0	2800.0	**2800**	**2875**	Revenues ($mill) A	**3350**
52.1	71.1	82.3	103.0	132.4	153.0	193.0	212.0	211.0	207.6	**210**	**225**	Net Profit ($mill)	**270**
33.1%	34.3%	40.7%	36.0%	35.9%	37.0%	37.7%	37.8%	37.6%	38.9%	**38.0%**	**38.0%**	Income Tax Rate	**38.0%**
4.9%	11.7%	7.8%	11.9%	13.5%	8.4%	7.1%	8.1%	8.5%	7.4%	**7.5%**	**7.8%**	Net Profit Margin	**8.1%**
45.3%	45.9%	61.3%	58.3%	50.3%	54.0%	51.9%	50.2%	50.2%	50.3%	**50.0%**	**46.5%**	Long-Term Debt Ratio	**45.0%**
49.2%	48.3%	38.7%	41.7%	49.7%	46.0%	48.1%	49.8%	49.8%	49.7%	**50.0%**	**53.5%**	Common Equity Ratio	**55.0%**
1345.8	1286.2	1736.3	1704.3	1901.4	3008.0	3114.0	3231.0	3335.0	3327.0	**3355**	**3225**	Total Capital ($mill)	**3350**
1598.9	1637.5	2058.9	2194.2	2352.4	3178.0	3271.0	3436.0	3566.0	3816.0	**3950**	**4100**	Net Plant ($mill)	**4400**
5.7%	7.4%	6.5%	8.1%	8.9%	6.3%	7.9%	8.0%	7.7%	7.5%	**7.5%**	**8.0%**	Return on Total Cap'l	**9.0%**
7.1%	10.2%	12.3%	14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	**12.5%**	**13.0%**	Return on Shr. Equity	**14.5%**
7.9%	11.5%	12.3%	14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	**12.5%**	**13.0%**	Return on Com Equity	**14.5%**
NMF	3.2%	4.2%	7.0%	6.6%	5.6%	6.2%	6.3%	5.3%	5.0%	**4.5%**	**5.0%**	Retained to Com Eq	**6.0%**
101%	72%	65%	52%	53%	49%	52%	52%	58%	60%	**64%**	**62%**	All Div'ds to Net Prof	**59%**

CURRENT POSITION ($MILL.)	2006	2007	12/31/08
Cash Assets	20.0	21.0	16.0
Other	1802.0	1790.0	2026.0
Current Assets	1822.0	1811.0	2042.0
Accts Payable	213.0	172.0	202.0
Debt Due	539.0	580.0	866.0
Other	875.0	893.0	915.0
Current Liab.	1627.0	1645.0	1983.0
Fix. Chg. Cov.	397%	391%	416%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	4.5%	17.5%	2.5%
"Cash Flow"	6.5%	7.0%	2.5%
Earnings	7.0%	11.5%	3.0%
Dividends	3.5%	6.5%	2.5%
Book Value	7.0%	11.5%	.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1044	436	434	707	2621
2007	973	467	369	685	2494
2008	1012	444	539	805	2800
2009	*1030*	*490*	*505*	*775*	*2800*
2010	*1045*	*505*	*520*	*805*	*2875*

Cal-endar	EARNINGS PER SHARE B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1.41	.25	.46	.60	2.72
2007	1.29	.40	.17	.86	2.72
2008	1.16	.30	.28	.97	2.71
2009	*1.20*	*.35*	*.30*	*.85*	*2.70*
2010	*1.25*	*.35*	*.35*	*.90*	*2.85*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.31	.31	.31	.37	1.30
2006	.37	.37	.37	.37	1.48
2007	.41	.41	.41	.41	1.64
2008	.42	.42	.42	.42	1.68
2009	.43				

BUSINESS: AGL Resources, Inc. is a public utility holding company. Its distribution subsidiaries include Atlanta Gas Light, Chattanooga Gas, and Virginia Natural Gas. The utilities have more than 2.2 million customers in Georgia, Virginia, Tennessee, New Jersey, Florida, and Maryland. Engaged in nonregulated natural gas marketing and other allied services. Also wholesales and retails propane. Deregulated subsidiaries: Georgia Natural Gas markets natural gas at retail. Sold Utilipro, 3/01. Acquired Compass Energy Services, 10/07. Officers/directors own less than 1.0% of common (3/08 Proxy). Pres. & CEO: John W. Somerhalder II. Inc.: GA. Addr.: Ten Peachtree Place N.E., Atlanta, GA 30309. Telephone: 404-584-4000. Internet: www.aglresources.com.

Shares of AGL Resources have held up better than the broader market over the past six months. That's owing to the steadiness of its underlying operations. Share net roughly equaled the tally reached in the prior two years. In 2008, healthy performances at the Wholesale Services and Energy Investments units were roughly offset by lower operating earnings at the Distribution and Retail Energy businesses. (Note: AGL is the stock's new ticker symbol).

The economic environment should remain challenging in the current year. Slower customer growth ought to hinder results at the company's utility operations. Moreover, we expect higher development and maintenance costs and a return to a more normal earnings level at the Wholesale Services business. Overall, AGL anticipates share net of $2.65-$2.75 for 2009, assuming normal weather patterns. Our estimate lies at the midpoint of this range. Bottom-line growth may well resume in 2010, assuming success at obtaining rate relief (discussed below).

The company is seeking higher rates. It will have four rate cases in the next two years, beginning with a filing in New Jersey. AGL's focus on procuring rate relief is encouraging, as the company depends upon such approved revenue increases to cope with higher costs and compensate it for investments made in its utility operations. Still, what pressures the rate boards may face remain unclear.

The board of directors has recently approved a modest dividend increase. Starting with the March payout, the quarterly dividend will now be $0.43. A modest increase makes sense, given stalled earnings growth and a lower cash balance in recent times. Slow, but steady, dividend growth will likely continue at AGL in the coming years.

This issue has good appeal at present. The shares have improved a notch in Timeliness since our December review, and are now ranked 2 (Above Average). Moreover, AGL earns high marks for Safety, Price Stability, and Earnings Predictability. In addition, the stock's healthy dividend yield should appeal to income investors. Overall, this equity offers attractive total return potential for a utility.

Michael Napoli, CPA *March 13, 2009*

(A) Fiscal year ends December 31st. Ended September 30th prior to 2002.
(B) Diluted earnings per share. Excl. nonrecurring gains (losses): '95, ($0.83); '99, $0.39; '00, $0.13; '01, $0.13; '03, ($0.07); '08, $0.13. Next earnings report due late April.
(C) Dividends historically paid early March, June, Sept., and Dec. ■ Div'd reinvest. plan available.
(D) Includes intangibles. In 2008: $418 million, $5.44/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	85

ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE	20.24	P/E RATIO	9.6 (Trailing: 10.0 / Median: 16.0)	RELATIVE P/E RATIO	0.93	DIV'D YLD	6.6%	VALUE LINE

TIMELINESS	2	Raised 12/12/08
SAFETY	2	Raised 12/16/05
TECHNICAL	2	Raised 3/13/09

BETA .60 (1.00 = Market)

High:	32.3	33.0	26.3	25.8	24.5	25.5	27.6	30.0	33.1	33.5	29.3	26.2
Low:	24.8	19.6	14.3	19.5	17.6	20.8	23.4	25.0	25.5	23.9	19.7	20.2

Target Price Range 2012 | 2013 | 2014

2012-14 PROJECTIONS

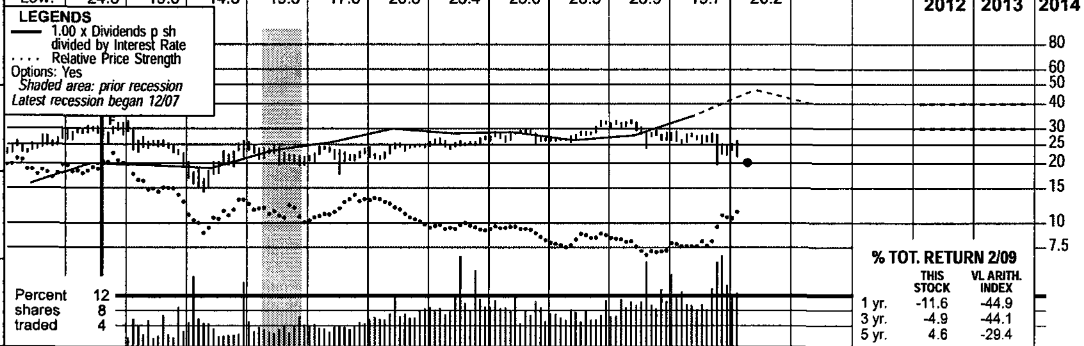
	Price	Gain	Ann'l Total Return
High	40	(+100%)	23%
Low	30	(+50%)	15%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	1	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	3	0	1	1	0	1	1

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	112	119	103
to Sell	103	89	119
Hld's(000)	58504	58318	56301



% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-11.6	-44.9
3 yr.	-4.9	-44.1
5 yr.	4.6	-29.4

Atmos Energy's history dates back to 1906 in the Texas Panhandle. Over the years, through various mergers, it became part of Pioneer Corporation, and, in 1981, Pioneer named its gas distribution division Energas. In 1983, Pioneer organized Energas as a separate subsidiary and distributed the outstanding shares of Energas to Pioneer shareholders. Energas changed its name to Atmos in 1988. Atmos acquired Trans Louisiana Gas in 1986, Western Kentucky Gas Utility in 1987, Greeley Gas in 1993, United Cities Gas in 1997, and others.

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
22.09	26.61	35.36	22.82	54.39	46.50	61.75	75.27	66.03	79.52	**82.60**	**84.95**	Revenues per sh A	**94.55**
2.62	3.01	3.03	3.39	3.23	2.91	3.90	4.26	4.14	4.19	**4.35**	**4.40**	"Cash Flow" per sh	**4.80**
.81	1.03	1.47	1.45	1.71	1.58	1.72	2.00	1.94	2.00	**2.10**	**2.15**	Earnings per sh A B	**2.50**
1.10	1.14	1.16	1.18	1.20	1.22	1.24	1.26	1.28	1.30	**1.32**	**1.34**	Div'ds Decl'd per sh C ■	**1.40**
3.53	2.36	2.77	3.17	3.10	3.03	4.14	5.20	4.39	5.20	**5.50**	**5.75**	Cap'l Spending per sh	**6.60**
12.09	12.28	14.31	13.75	16.66	18.05	19.90	20.16	22.01	22.60	**24.05**	**24.70**	Book Value per sh	**26.90**
31.25	31.95	40.79	41.68	51.48	62.80	80.54	81.74	89.33	90.81	**92.00**	**93.00**	Common Shs Outst'g D	**110.00**
33.0	18.9	15.6	15.2	13.4	15.9	16.1	13.5	15.9	13.6	*Bold figures are*		Avg Ann'l P/E Ratio	**14.0**
1.88	1.23	.80	.83	.76	.84	.86	.73	.84	.84	*Value Line*		Relative P/E Ratio	**.95**
4.1%	5.9%	5.1%	5.4%	5.2%	4.9%	4.5%	4.7%	4.2%	4.8%	*estimates*		Avg Ann'l Div'd Yield	**4.0%**
690.2	850.2	1442.3	950.8	2799.9	2920.0	4973.3	6152.4	5898.4	7221.3	**7600**	**7900**	Revenues ($mill) A	**10400**
25.0	32.2	56.1	59.7	79.5	86.2	135.8	162.3	170.5	180.3	**195**	**200**	Net Profit ($mill)	**275**
35.0%	36.1%	37.3%	37.1%	37.1%	37.4%	37.7%	37.6%	35.8%	38.4%	**39.0%**	**39.0%**	Income Tax Rate	**40.5%**
3.6%	3.8%	3.9%	6.3%	2.8%	3.0%	2.7%	2.6%	2.9%	2.5%	**2.6%**	**2.5%**	Net Profit Margin	**2.6%**
50.0%	48.1%	54.3%	53.9%	50.2%	43.2%	57.7%	57.0%	52.0%	50.8%	**48.5%**	**48.0%**	Long-Term Debt Ratio	**49.0%**
50.0%	51.9%	45.7%	46.1%	49.8%	56.8%	42.3%	43.0%	48.0%	49.2%	**51.5%**	**52.0%**	Common Equity Ratio	**51.0%**
755.1	755.7	1276.3	1243.7	1721.4	1994.8	3785.5	3828.5	4092.1	4172.3	**4300**	**4415**	Total Capital ($mill)	**5800**
965.8	982.3	1335.4	1300.3	1516.0	1722.5	3374.4	3629.2	3836.8	4136.9	**4350**	**4560**	Net Plant ($mill)	**5850**
5.1%	6.5%	5.9%	6.8%	6.2%	5.8%	5.3%	6.1%	5.9%	5.9%	**6.0%**	**6.0%**	Return on Total Cap'l	**6.0%**
6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	**9.0%**	**8.5%**	Return on Shr. Equity	**9.5%**
6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	**9.0%**	**8.5%**	Return on Com Equity	**9.5%**
NMF	NMF	2.1%	1.9%	2.8%	1.7%	2.3%	3.6%	3.0%	3.1%	**3.5%**	**3.5%**	Retained to Com Eq	**4.0%**
NMF	112%	79%	82%	70%	77%	73%	63%	65%	65%	**62%**	**62%**	All Div'ds to Net Prof	**56%**

CAPITAL STRUCTURE as of 12/31/08
Total Debt $2481.2 mill. **Due in 5 Yrs** $1360.0 mill.
LT Debt $1719.9 mill. **LT Interest** $105.0 mill.
(LT interest earned: 2.9x; total interest coverage: 2.8x)
Leases, Uncapitalized Annual rentals $18.4 mill.
Pfd Stock None
Pension Assets-9/08 $341.4 mill. **Oblig.** $337.6 mill.
Common Stock 91,634,602 shs. **as of 1/27/09**
MARKET CAP: $1.9 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2007	2008	12/31/08
Cash Assets	60.7	46.7	69.8
Other	1008.2	1238.4	1613.3
Current Assets	1068.9	1285.1	1683.1
Accts Payable	355.3	395.4	815.1
Debt Due	154.4	351.3	761.3
Other	410.0	460.4	441.5
Current Liab.	919.7	1207.1	2017.9
Fix. Chg. Cov.	405%	450%	430%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	9.5%	14.5%	*4.0%*
"Cash Flow"	3.5%	5.5%	*2.5%*
Earnings	2.5%	5.0%	*4.0%*
Dividends	2.5%	1.5%	*1.5%*
Book Value	6.5%	7.5%	*4.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	2283.8	2033.8	863.2	971.6	6152.4
2007	1602.6	2075.6	1218.2	1002.0	5898.4
2008	1657.5	2484.0	1639.1	1440.7	7221.3
2009	1716.3	**2585**	**1750**	**1548.7**	**7600**
2010	**1830**	**2900**	**1710**	**1460**	**7900**

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	.88	1.10	d.22	.25	2.00
2007	.97	1.20	d.15	d.05	1.94
2008	.82	1.24	d.07	.02	2.00
2009	.83	**1.33**	**d.05**	**d.01**	**2.10**
2010	**.90**	**1.35**	**d.06**	**d.04**	**2.15**

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.31	.31	.31	.315	1.25
2006	.315	.315	.315	.32	1.27
2007	.32	.32	.32	.325	1.29
2008	.325	.325	.325	.33	1.31
2009	.33				

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to 3.2 million customers via six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Combined 2008 gas volumes: 293 MMcf. Breakdown: 56%, residential; 32%, commercial; 7%, industrial; and 5% other. 2008 depreciation rate 3.5%. Has around 4,560 employees. Officers and directors own approximately 1.9% of common stock (12/08 Proxy). Chairman and Chief Executive Officer: Robert W. Best. Incorporated: Texas. Address: P.O. Box 650205, Dallas, Texas 75265. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy's core natural gas utility has performed nicely thus far in fiscal 2009 (which ends on September 30th). That can be attributed partially to an increase in rates, primarily for the Mid-Tex and Louisiana divisions. What's more, there has been a steady rise in throughput. And it's worth noting that bad debt expense as a percentage of revenues has been lower, reflecting more aggressive collection efforts.

Results for the other operations have been a mixed bag. The pipeline and storage segment is enjoying expanded transportation margins earned under asset optimization agreements. But the performance of the regulated transmission and storage segment is being weighed down by a rise in employee and pipeline maintenance costs. Also, the nonregulated marketing segment is encountering a reduction in unrealized margins, reflecting less volatility in natural gas prices.

All things considered, earnings per share stand to rise around 5%, to $2.10, this fiscal year. Assuming further expansion in operating margins, the bottom line may advance to $2.15 a share in fiscal 2010.

We envision steady, though unexciting, profit growth over the 2012-2014 period. The utility is one of the country's leading natural gas-only distributors, now serving customers across 12 states. Moreover, the unregulated segments, especially pipelines, possess healthy overall prospects. Lastly, management may get back to its successful strategy of purchasing less-efficient utilities and shoring up their profitability via expense-reduction efforts, rate relief, and aggressive marketing. In the present configuration, annual share-net gains may be in the mid-single-digit range over the 3- to 5-year time frame.

The good-quality stock offers an appealing dividend yield. Further moderate hikes in the payout seem plausible, as well. Earnings coverage ought to remain adequate. The shares are timely.

For a natural gas utility stock, total return possibilities appear decent. Meter growth has slowed, but the company is benefiting from a high level of gas flowing through its Texas pipelines from the Barnett Shale.

Frederick L. Harris, III *March 13, 2009*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '99, d23¢; '00, 12¢; '03, d17¢; '06, d18¢; '07, d2¢. Next egs. rpt. due early May. (C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. (D) In millions. (E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	80

LACLEDE GROUP NYSE-LG

RECENT PRICE **38.10** | P/E RATIO **13.4** (Trailing: 12.4 / Median: 15.0) | RELATIVE P/E RATIO **1.30** | DIV'D YLD **4.1%** | VALUE LINE

TIMELINESS 2 Raised 10/10/08
SAFETY 2 Raised 6/20/03
TECHNICAL 3 Lowered 2/13/09
BETA .65 (1.00 = Market)

2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+55%)	15%
Low	45	(+20%)	8%

Insider Decisions

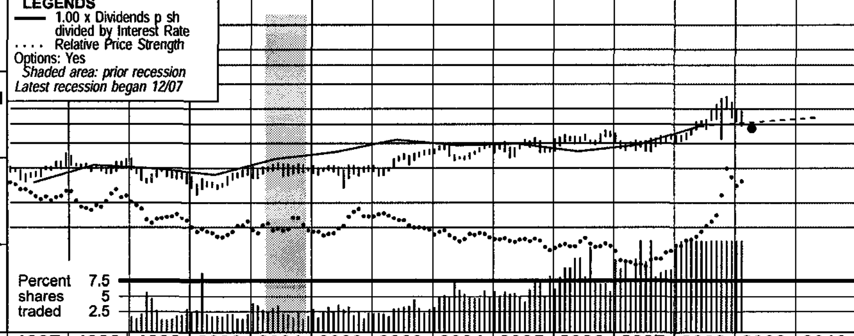
	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	9	0	0	2	0	0	6	0
to Sell	0	9	0	0	2	0	0	6	0

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	72	97	82
to Sell	55	50	72
Hld's(000)	10492	11750	11943

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	27.9	27.0	24.8	25.5	25.0	30.0	32.5	34.3	37.5	36.0	55.8	48.3
Low:	22.4	20.0	17.5	21.3	19.0	21.8	26.0	26.9	29.1	28.8	31.9	38.0

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



Target Price Range
2012 | 2013 | 2014

% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	20.3	-44.9
3 yr.	33.3	-44.1
5 yr.	58.9	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
32.33	33.43	24.79	31.03	34.33	31.04	26.04	29.99	53.08	39.84	54.95	59.59	75.43	93.51	93.40	100.44	*102.65*	*96.10*	Revenues per sh	*111.55*
2.81	2.65	2.55	3.29	3.32	3.02	2.56	2.68	3.00	2.56	3.15	2.79	2.98	3.81	3.87	4.22	*4.65*	*4.50*	"Cash Flow" per sh	*5.40*
1.61	1.42	1.27	1.87	1.84	1.58	1.47	1.37	1.61	1.18	1.82	1.82	1.90	2.37	2.31	2.64	*2.85*	*2.60*	Earnings per sh A B	*3.00*
1.22	1.22	1.24	1.26	1.30	1.32	1.34	1.34	1.34	1.34	1.34	1.35	1.37	1.40	1.45	1.49	*1.53*	*1.57*	Div'ds Decl'd per sh C ■	*1.70*
2.62	2.50	2.63	2.35	2.44	2.68	2.58	2.77	2.51	2.80	2.67	2.45	2.84	2.97	2.72	2.57	*2.65*	*2.70*	Cap'l Spending per sh	*3.45*
12.19	12.44	13.05	13.72	14.26	14.57	14.96	14.99	15.26	15.07	15.65	16.96	17.31	18.85	19.79	22.12	*23.60*	*25.10*	Book Value per sh D	*28.05*
15.59	15.67	17.42	17.56	17.56	17.63	18.88	18.88	18.88	18.96	19.11	20.98	21.17	21.36	21.65	21.99	*22.50*	*23.00*	Common Shs Outst'g E	*26.00*
13.5	16.4	15.5	11.9	12.5	15.5	15.8	14.9	14.5	20.0	13.6	15.7	16.2	13.6	14.2	14.3	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
.80	1.08	1.04	.75	.72	.81	.90	.97	.74	1.09	.78	.83	.86	.73	.75	.89	*Value Line*		Relative P/E Ratio	*1.15*
5.6%	5.3%	6.3%	5.6%	5.6%	5.4%	5.8%	6.6%	5.7%	5.7%	5.4%	4.7%	4.4%	4.3%	4.4%	3.9%	*estimates*		Avg Ann'l Div'd Yield	*3.2%*

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
491.6	566.1	1002.1	755.2	1050.3	1250.3	1597.0	1997.6	2021.6	2209.0	*2310*	*2210*	Revenues ($mill) A	*2900*
26.9	26.0	30.5	22.4	34.6	36.1	40.1	50.5	49.8	57.6	*65.0*	*60.0*	Net Profit ($mill)	*80.0*
35.5%	35.2%	32.7%	35.4%	35.0%	34.8%	34.1%	32.5%	33.4%	31.3%	*31.5%*	*31.5%*	Income Tax Rate	*35.0%*
5.5%	4.6%	3.0%	3.0%	3.3%	2.9%	2.5%	2.5%	2.5%	2.6%	*2.8%*	*2.7%*	Net Profit Margin	*2.8%*
41.8%	45.2%	49.5%	47.5%	50.4%	51.6%	48.1%	49.5%	45.3%	44.4%	*45.0%*	*45.0%*	Long-Term Debt Ratio	*47.0%*
57.8%	54.5%	50.2%	52.3%	49.4%	48.3%	51.8%	50.4%	54.6%	55.5%	*55.0%*	*55.0%*	Common Equity Ratio	*53.0%*
488.6	519.2	574.1	546.6	605.0	737.4	707.9	798.9	784.5	876.1	*965*	*1050*	Total Capital ($mill)	*1375*
519.4	575.4	602.5	594.4	621.2	646.9	679.5	763.8	793.8	823.2	*855*	*880*	Net Plant ($mill)	*980*
7.1%	6.7%	6.9%	6.0%	7.4%	6.6%	7.6%	8.4%	8.5%	8.1%	*8.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
9.5%	9.1%	10.5%	7.8%	11.5%	10.1%	10.9%	12.5%	11.6%	11.8%	*12.5%*	*10.5%*	Return on Shr. Equity	*11.0%*
9.5%	9.1%	10.5%	7.8%	11.6%	10.1%	10.9%	12.5%	11.6%	11.8%	*12.5%*	*10.5%*	Return on Com Equity	*11.0%*
1.0%	.2%	1.8%	NMF	3.1%	2.7%	3.1%	5.1%	4.3%	5.2%	*6.0%*	*4.0%*	Retained to Com Eq	*5.0%*
89%	98%	83%	113%	74%	73%	72%	59%	63%	56%	*53%*	*60%*	All Div'ds to Net Prof	*55%*

CAPITAL STRUCTURE as of 12/31/08
Total Debt $652.9 mill. **Due in 5 Yrs** $50.0 mill.
LT Debt $389.2 mill. **LT Interest** $25.0 mill.
(Total interest coverage: 3.0x)

Leases, Uncapitalized Annual rentals $.9 mill.
Pension Assets-9/08 $248.3 mill. **Oblig.** $308.7 mill.
Pfd Stock $.5 mill. **Pfd Div'd** $.03 mill.
Common Stock 22,135,185 shs. as of 1/29/09

MARKET CAP: $850 million (Small Cap)

CURRENT POSITION ($MILL.)	2007	2008	12/31/08
Cash Assets	52.7	14.9	30.1
Other	414.6	547.0	609.8
Current Assets	467.3	561.9	639.9
Accts Payable	106.8	159.6	175.3
Debt Due	251.6	216.1	263.7
Other	115.3	103.5	121.7
Current Liab.	473.7	479.2	560.7
Fix. Chg. Cov.	282%	377%	330%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	11.5%	14.0%	2.5%
"Cash Flow"	2.0%	6.5%	5.5%
Earnings	3.5%	9.5%	3.5%
Dividends	1.0%	1.5%	2.5%
Book Value	3.5%	5.5%	5.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	689.2	708.8	330.6	269.0	1997.6
2007	539.6	700.8	457.9	323.3	2021.6
2008	504.0	747.7	505.5	451.8	2209.0
2009	674.3	*700*	*485*	*450.7*	*2310*
2010	*555*	*555*	*550*	*550*	*2210*

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	1.23	1.05	.13	d.04	2.37
2007	.89	.97	.43	.03	2.31
2008	.99	1.39	.41	d.14	2.64
2009	1.42	*1.25*	*.30*	*d.12*	*2.85*
2010	*1.03*	*1.21*	*.38*	*d.02*	*2.60*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.34	.345	.345	.345	1.38
2006	.345	.355	.355	.355	1.41
2007	.365	.365	.365	.365	1.46
2008	.375	.375	.375	.375	1.50
2009	.385				

BUSINESS: Laclede Group, Inc., is a holding company for Laclede Gas, which distributes natural gas in eastern Missouri, including the city of St. Louis, St. Louis County, and parts of 10 other counties. Has roughly 630,000 customers. Purchased SM&P Utility Resources, 1/02; divested, 3/08. Therms sold and transported in fiscal 2008: 1.08 mill. Revenue mix for regulated operations: residential, 62%; commercial and industrial, 24%; transportation, 1%; other, 13%. Has around 1,807 employees. Officers and directors own approximately 7.2% of common shares (1/09 proxy). Chairman, Chief Executive Officer, and President: Douglas H. Yaeger. Incorporated: Missouri. Address: 720 Olive Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.thelacledegroup.com.

Laclede Group started fiscal 2009 (which ends on September 30th) in excellent fashion. That was made possible primarily by Laclede Energy Resources, which benefited, in part, from higher volumes (attributable to contracting for additional pipeline capacity). That division also enjoyed wider margins on sales of natural gas, due to depressed supply pricing in the Midwest from increased shale supply production. Meanwhile, profits for Laclede Gas were moderately higher than the year-earlier figure, arising from greater income from natural gas sales, brought about by colder weather and higher Infrastructure System Replacement Surcharge revenues. But a rise in both operating expenses and investment losses largely offset these results.

At this juncture, the bottom line stands to advance about 8%, to $2.85 a share, in fiscal 2009. Earnings may be lower next year, however, because of the tough comparison.

Unexciting results appear to be in store for the energy firm over the 2012-2014 period. Growth in the customer base for the natural gas distribution unit will probably remain moderate. (In fact, the number of customers in fiscal 2008 was just 2% higher than in fiscal 1998.) That's because the service territory, located in eastern Missouri, is in a mature phase. We think the non-regulated division has promising expansion opportunities, but it has contributed only a small portion to Laclede Group's profits on a historical basis. A major acquisition could help to offset this, but it seems that no such plans are on the agenda at this time. Consequently, annual earnings-per-share growth could be just between 4% and 5% over the 3- to 5-year horizon.

This stock, ranked favorably for both Timeliness and Safety, offers a modestly appealing current yield. Additional hikes in the dividend will likely be gradual, though. That is largely because of the regulated gas operation's unspectacular long-term prospects.

The shares of Laclede have limited long-term total-return potential, given the current quotation and our assumption of moderate future increases in the distribution.

Frederick L. Harris, III *March 13, 2009*

(A) Fiscal year ends Sept. 30th.
(B) Based on average shares outstanding thru. '97, then diluted. Excludes nonrecurring loss: '06, 7¢. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late April. (C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '08: $340.4 mill., $15.48/sh.
(E) In millions.
(F) Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	75

NEW JERSEY RES. NYSE-NJR

RECENT PRICE	32.25	P/E RATIO	12.9 (Trailing: 11.7 Median: 15.0)	RELATIVE P/E RATIO	1.25	DIV'D YLD	3.8%	VALUE LINE

TIMELINESS 2 Raised 11/28/08
SAFETY 1 Raised 9/15/06
TECHNICAL 2 Raised 11/21/08
BETA .65 (1.00 = Market)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	17.9	18.3	19.8	21.7	22.4	26.4	29.7	32.9	35.4	37.6	41.1	42.4					
Low:	14.0	14.9	16.1	16.6	16.2	20.0	24.3	27.1	27.7	30.3	24.6	32.2					

Target Price Range
2012 | 2013 | 2014

2012-14 PROJECTIONS

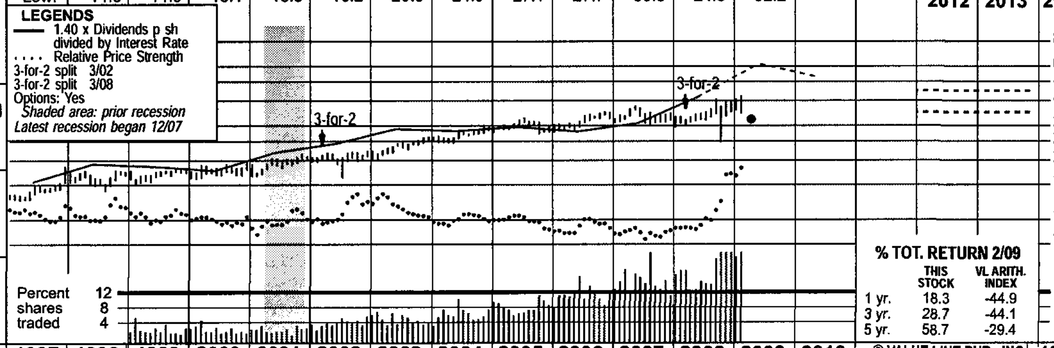
	Price	Gain	Ann'l Total Return
High	45	(+40%)	12%
Low	35	(+10%)	6%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	1	2	0	0	1	0	1	2	3
to Sell	0	2	0	0	1	0	0	1	4

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	85	90	64
to Sell	70	62	88
Hld's(000)	26518	26910	26312



% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	18.3	-44.9
3 yr.	28.7	-44.1
5 yr.	58.7	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
12.02	12.81	11.36	13.48	17.31	17.73	22.65	29.42	51.22	44.11	62.29	60.89	76.19	79.63	72.62	90.74	**89.20**	**90.95**	Revenues per sh A	**95.00**
1.42	1.54	1.42	1.48	1.63	1.74	1.86	1.99	2.12	2.14	2.38	2.50	2.62	2.73	2.44	3.62	**3.40**	**3.60**	"Cash Flow" per sh	**3.75**
.76	.84	.86	.92	.99	1.04	1.11	1.20	1.30	1.39	1.59	1.70	1.77	1.87	1.55	2.70	**2.50**	**2.70**	Earnings per sh B	**2.85**
.68	.68	.68	.69	.71	.73	.75	.76	.78	.80	.83	.87	.91	.96	1.01	1.11	**1.24**	**1.28**	Div'ds Decl'd per sh C■	**1.40**
1.54	1.40	1.18	1.19	1.15	1.07	1.21	1.23	1.10	1.02	1.14	1.45	1.28	1.28	1.46	1.72	**1.75**	**1.75**	Cap'l Spending per sh	**1.80**
6.54	6.43	6.47	6.73	6.92	7.26	7.57	8.29	8.80	8.71	10.26	11.25	10.60	15.00	15.50	17.28	**18.80**	**20.75**	Book Value per sh D	**25.75**
37.84	38.93	40.03	40.69	40.23	40.07	39.92	39.59	40.00	41.50	40.85	41.61	41.32	41.44	41.61	42.06	**42.50**	**43.00**	Common Shs Outst'g E	**45.00**
15.1	13.0	11.8	13.6	13.5	15.3	15.2	14.7	14.2	14.7	14.0	15.3	16.8	16.1	21.6	12.3	*Bold figures are*		Avg Ann'l P/E Ratio	**14.0**
.89	.85	.79	.85	.78	.80	.87	.96	.73	.80	.80	.81	.89	.87	1.15	.77	*Value Line*		Relative P/E Ratio	**.95**
5.8%	6.2%	6.7%	5.6%	5.3%	4.6%	4.5%	4.4%	4.2%	3.9%	3.7%	3.3%	3.1%	3.2%	3.0%	3.3%	*estimates*		Avg Ann'l Div'd Yield	**3.4%**

CAPITAL STRUCTURE as of 12/31/08
Total Debt $757.1 mill. Due in 5 Yrs $175.6 mill.
LT Debt $460.7 mill. LT Interest $16.9 mill.
Incl. $8.8 mill. capitalized leases.
(LT interest earned: 4.8x; total interest coverage: 4.8x)
Pension Assets-9/08 $80.6 mill. **Oblig.** $102.4 mill.

Pfd Stock None

Common Stock 42,318,558 shs. as of 2/4/09
MARKET CAP: $1.4 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
904.3	1164.5	2048.4	1830.8	2544.4	2533.6	3148.3	3299.6	3021.8	3816.2	**3790**	**3910**	Revenues ($mill) A	**4275**
44.9	47.9	52.3	56.8	65.4	71.6	74.4	78.5	65.3	113.9	**105**	**115**	Net Profit ($mill)	**130**
36.2%	37.8%	38.0%	38.7%	39.4%	39.1%	39.1%	38.9%	38.8%	37.8%	**39.0%**	**39.0%**	Income Tax Rate	**40.0%**
5.0%	4.1%	2.6%	3.1%	2.6%	2.8%	2.4%	2.4%	2.2%	3.0%	**2.8%**	**3.0%**	Net Profit Margin	**3.0%**
48.7%	47.0%	50.1%	50.6%	38.1%	40.3%	42.0%	34.8%	37.3%	38.5%	**38.5%**	**37.0%**	Long-Term Debt Ratio	**33.0%**
51.2%	52.9%	49.9%	49.4%	61.9%	59.7%	58.0%	65.2%	62.7%	61.5%	**61.5%**	**63.0%**	Common Equity Ratio	**67.0%**
590.4	620.1	706.2	732.4	676.8	783.8	755.3	954.0	1028.0	1182.1	**1300**	**1415**	Total Capital ($mill)	**1730**
705.4	730.6	743.9	756.4	852.6	880.4	905.1	934.9	970.9	1017.3	**1040**	**1060**	Net Plant ($mill)	**1125**
9.0%	9.0%	8.5%	8.7%	10.7%	10.1%	11.2%	9.6%	7.7%	10.7%	**9.0%**	**9.0%**	Return on Total Cap'l	**8.0%**
14.8%	14.6%	14.8%	15.7%	15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	**13.5%**	**13.0%**	Return on Shr. Equity	**11.0%**
14.8%	14.6%	14.9%	15.7%	15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	**13.5%**	**13.0%**	Return on Com Equity	**11.0%**
5.0%	5.4%	6.1%	6.9%	7.7%	7.8%	8.5%	6.3%	3.6%	9.5%	**6.5%**	**7.0%**	Retained to Com Eq	**5.5%**
67%	63%	59%	56%	51%	49%	50%	50%	64%	40%	**50%**	**47%**	All Div'ds to Net Prof	**49%**

CURRENT POSITION ($MILL.)

	2007	2008	12/31/08
Cash Assets	5.1	42.6	26.0
Other	794.8	1067.1	1046.5
Current Assets	799.9	1109.7	1072.5
Accts Payable	64.4	61.7	43.4
Debt Due	260.8	238.3	296.4
Other	378.1	594.0	578.7
Current Liab.	703.3	894.0	918.5
Fix. Chg. Cov.	461%	450%	450%

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	17.5%	9.0%	2.5%
"Cash Flow"	6.0%	6.0%	4.0%
Earnings	7.5%	7.5%	5.5%
Dividends	4.0%	5.0%	5.5%
Book Value	8.5%	11.5%	8.5%

QUARTERLY REVENUES ($ mill.) A

Fiscal Year Ends	Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	1164	1064	536.1	535.5	3299.6
2007	737.4	1029	662.2	593.2	3021.8
2008	811.1	1178	1000	827.1	3816.2
2009	801.3	*1175*	*993.7*	*820*	*3790*
2010	*830*	*1205*	*1025*	*850*	*3910*

EARNINGS PER SHARE A B

Fiscal Year Ends	Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	.82	1.43	d.09	d.29	1.87
2007	.70	.19	.60	.06	1.55
2008	.87	.30	d.18	1.86	2.70
2009	.77	*.33*	*d.10*	*1.50*	*2.50*
2010	*.80*	*.40*	*d.05*	*1.55*	*2.70*

QUARTERLY DIVIDENDS PAID C E■

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.227	.227	.227	.227	.91
2006	.24	.24	.24	.24	.96
2007	.253	.253	.253	.253	1.01
2008	.267	.28	.28	.28	1.11
2009	.31				

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in New Jersey, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had about 484,000 customers at 9/30/08 in Monmouth and Ocean Counties, and other N.J. Counties. Fiscal 2008 volume: 99.6 bill. cu. ft. (59% firm, 6% interruptible industrial and electric utility, 35% off-system and capacity release). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2008 dep. rate: 2.9%. Has 854 empls. Off./dir. own about 1.7% of common (12/08Proxy). Chrmn., CEO, & Pres. : Laurence M. Downes. Inc.: N.J. Addr.: 1415 Wyckoff Road, Wall, NJ 07719. Tel.: 732-938-1480. Web: www.njresources.com.

New Jersey Resources did not perform as well as expected during its 2009 fiscal first quarter (ended December 31st). The New Jersey Natural Gas (NJNG) unit did benefit from a recent rate case increase, and steady customer growth. That division added roughly 1,765 new customers over the December interim. However, that was not sufficient enough to offset the downturn at the company's NJR Energy Services (NJRES) unit. Narrower winter storage spreads, and a slowdown in contracted transportation capacity across the Northeast, cut this segment's contribution to earnings in half. Consequently, NJR's bottom line suffered.

Thus, we have trimmed this year's earnings figure approximately 11%. The domestic recession has prompted many consumers in NJR's service areas to scale back spending. Meanwhile, home foreclosure resulting in vacant domiciles adds another element of risk and uncertainty. In all, 2009's prospects have been hindered. But, on a brighter note,

Economic stimulus programs may bear fruit down the road. NJNG recently filed a proposal with the New Jersey Board of Public Utilities for two programs aimed at stimulating the local economy through energy efficiency, job creation, and infrastructure spending. If approved, these capital projects would create up to 100 jobs. The benefit to NJR would be an increase in the safety and reliability of its distribution system.

Meantime, we have introduced a 2010 bottom-line estimate of $2.70 a share. Top-line volumes ought to rebound next year due to the addition of utility customers, coupled with NJRES' capital projects. The Steckman Ridge storage facility and the recently completed 16-inch main pipeline both ought to contribute nicely.

These timely shares may appeal to momentum- and income-oriented accounts (Timeliness: 2). And the recent dividend hike of 10.7% only sweetens the deal; dividend growth is a hallmark here. Finally, New Jersey Resources' ability to hold up in such a difficult market is a plus. This characteristic is supported by the stock's top Safety rank (1), and high marks for Financial Strength and Price Stability.

Bryan Fong *March 13, 2009*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly egs may not sum to total due to change in shares outstanding. Next earnings report due late April.
(C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2008: $340.7 million, $8.09/share.
(E) In millions, adjusted for split.
(F) Restated.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	50

NICOR, INC. NYSE-GAS

RECENT PRICE	29.17	P/E RATIO	11.4 (Trailing: 11.1) (Median: 15.0)	RELATIVE P/E RATIO	1.11	DIV'D YLD	6.4%	VALUE LINE

TIMELINESS 3 Raised 12/7/07

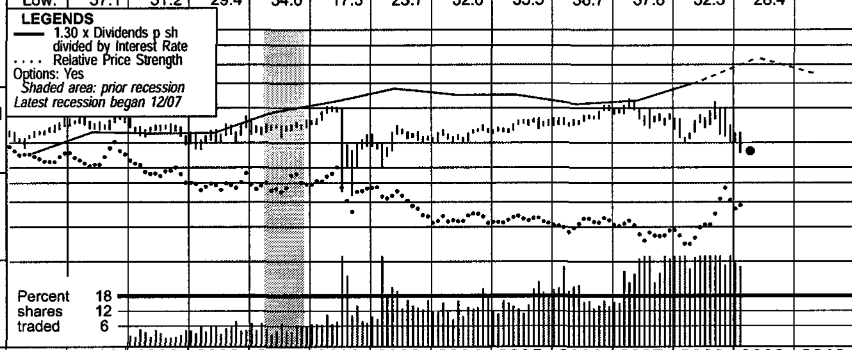
SAFETY 3 Lowered 6/17/05

TECHNICAL 3 Lowered 2/20/09

BETA .75 (1.00 = Market)

High:	44.4	42.9	43.9	42.4	49.0	39.3	39.7	43.0	49.9	53.7	52.0	36.3		
Low:	37.1	31.2	29.4	34.0	17.3	23.7	32.0	35.5	38.7	37.8	32.3	28.4		

LEGENDS
— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



Target Price Range

2012	2013	2014

2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+125%)	26%
Low	40	(+35%)	13%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	1	0	0	0
to Sell	0	0	0	0	0	1	0	0	0

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	91	119	105
to Sell	120	90	125
Hld's(000)	31875	32273	32539

Percent shares traded 18 12 6

% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-3.5	-44.9
3 yr.	-16.5	-44.1
5 yr.	9.5	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
31.02	31.23	29.42	37.39	41.33	30.84	34.45	50.52	57.30	43.11	60.46	62.12	76.00	65.92	69.20	83.68	78.90	82.20	Revenues per sh	98.35
3.80	4.11	4.19	4.97	5.29	5.21	5.59	6.16	6.41	6.03	5.37	6.00	6.19	6.82	6.96	6.85	6.50	7.00	"Cash Flow" per sh	7.95
1.97	2.07	1.96	2.42	2.55	2.31	2.57	2.94	3.01	2.88	2.11	2.22	2.27	2.87	2.99	2.63	2.50	2.90	Earnings per sh A	3.30
1.22	1.25	1.28	1.32	1.40	1.48	1.54	1.66	1.76	1.84	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	Div'ds Decl'd per sh B■	1.86
2.62	3.34	3.12	2.42	2.34	2.87	3.28	3.48	4.18	4.37	4.12	4.32	4.57	4.17	3.77	5.54	4.35	4.50	Cap'l Spending per sh	4.85
13.05	13.26	13.67	14.74	15.43	15.97	16.80	15.56	16.39	16.55	17.13	16.99	18.36	19.43	20.58	21.55	22.25	23.30	Book Value per sh	27.05
53.96	51.54	50.30	49.49	48.22	47.51	46.89	45.49	44.40	44.01	44.04	44.10	44.18	44.90	45.90	45.13	45.00	45.00	Common Shs Outst'g C	45.00
14.1	12.5	13.1	12.5	14.2	17.6	14.6	11.9	12.8	13.1	15.8	15.9	17.3	15.0	15.0	15.1	Bold figures are		Avg Ann'l P/E Ratio	16.0
.83	.82	.88	.78	.82	.92	.83	.77	.66	.72	.90	.84	.92	.81	.80	.93	Value Line		Relative P/E Ratio	1.05
4.4%	4.8%	5.0%	4.4%	3.9%	3.6%	4.1%	4.7%	4.6%	4.9%	5.6%	5.3%	4.7%	4.3%	4.2%	4.7%	estimates		Avg Ann'l Div'd Yield	3.5%

CAPITAL STRUCTURE as of 12/31/08
Total Debt $1237.9 mill. **Due in 5 Yrs** $914.9 mill.
LT Debt $448.0 mill. **LT Interest** $5.0 mill.
(Total interest coverage: 5.1x)

Pension Assets-12/08 $306.6 mill. **Oblig.** $270.2 mill.

Pfd Stock $.6 mill. **Pfd Div'd** None

Common Stock 45,198,311 shares as of 2/17/09
MARKET CAP: $1.3 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
1615.2	2298.1	2544.1	1897.4	2662.7	2739.7	3357.8	2960.0	3176.3	3776.6	3550	3700	Revenues ($mill)	4200
121.9	136.4	136.3	128.0	93.1	98.1	101.1	128.3	135.2	119.5	112.5	130	Net Profit ($mill)	150
34.7%	34.8%	33.5%	31.0%	35.2%	31.8%	28.3%	26.3%	26.6%	27.0%	27.0%	27.0%	Income Tax Rate	27.0%
7.5%	5.9%	5.4%	6.7%	3.5%	3.6%	3.0%	4.3%	4.3%	3.2%	3.2%	3.5%	Net Profit Margin	3.6%
35.5%	32.7%	37.8%	35.1%	39.6%	39.8%	37.4%	36.3%	30.9%	31.5%	31%	30%	Long-Term Debt Ratio	26%
64.0%	66.7%	61.7%	64.5%	60.3%	60.1%	62.5%	63.7%	69.0%	68.4%	69%	70%	Common Equity Ratio	74%
1230.1	1061.2	1180.1	1128.9	1251.5	1246.0	1297.7	1370.7	1368.0	1421.1	1450	1500	Total Capital ($mill)	1650
1735.2	1729.6	1768.6	1796.8	2484.2	2549.8	2659.1	2714.1	2757.3	2858.6	2950	3060	Net Plant ($mill)	3380
10.9%	13.7%	12.3%	12.2%	8.3%	8.8%	9.4%	10.9%	11.2%	9.7%	9.0%	10.0%	Return on Total Cap'l	10.0%
15.4%	19.1%	18.6%	17.5%	12.3%	13.1%	12.5%	14.7%	14.3%	12.3%	11.0%	12.5%	Return on Shr. Equity	12.0%
15.4%	19.2%	18.7%	17.5%	12.3%	13.1%	12.5%	14.7%	14.3%	12.3%	11.0%	12.5%	Return on Com Equity	12.0%
6.2%	8.5%	7.9%	6.5%	1.5%	2.1%	2.3%	5.2%	5.4%	3.6%	3.0%	4.5%	Retained to Com Eq	5.5%
60%	56%	58%	63%	88%	84%	81%	65%	62%	71%	74%	64%	All Div'ds to Net Prof	56%

CURRENT POSITION ($MILL.)	2006	2007	12/31/08
Cash Assets	67.6	91.9	95.5
Other	843.1	931.9	1243.4
Current Assets	910.7	1023.8	1338.9
Accts Payable	564.5	428.2	411.3
Debt Due	350.0	444.0	789.9
Other	227.9	404.2	466.8
Current Liab.	1142.4	1276.4	1668.0
Fix. Chg. Cov.	543%	544%	461%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	7.0%	6.5%	5.0%
"Cash Flow"	3.0%	3.0%	2.5%
Earnings	1.5%	1.0%	2.5%
Dividends	3.0%	0.5%	Nil
Book Value	3.0%	4.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1319.4	451.3	351.1	838.2	2960.0
2007	1334.7	556.9	365.2	919.5	3176.3
2008	1595.7	699.8	440.3	1040.8	3776.6
2009	1500	650	400	1000	3550
2010	1550	675	425	1050	3700

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.99	.19	.39	1.30	2.87
2007	1.04	.40	.32	1.22	2.98
2008	.91	.64	.03	1.05	2.63
2009	.90	.35	.25	1.00	2.50
2010	1.00	.45	.35	1.10	2.90

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.465	.465	.465	.465	1.86
2006	.465	.465	.465	.465	1.86
2007	.465	.465	.465	.465	1.86
2008	.465	.465	.465	.465	1.86
2009	.465	.465			

BUSINESS: Nicor Inc. is a holding company with gas distribution as its primary business. Serves over 2.2 million customers in northern and western Illinois. 2008 gas delivered: 498.1 Bcf, incl. 222.6 Bcf from transportation. 2008 gas sales (275.5 bcf): residential, 93%; commercial, 6%; industrial, 1%. Principal supplying pipelines: Natural Gas Pipeline, Horizon Pipeline, and TGPC. Current operations include Tropical Shipping subsidiary and several energy related ventures. Divested oil and gas E&P, 6/93. Has about 3,900 employees. *Officers/directors own about 2.2% of common stock (3/08 proxy).* Chairman and Chief Executive Officer: Russ Strobel. Incorporated: Illinois. Address: 1844 Ferry Road, Naperville, Illinois 60563. Telephone: 630-305-9500. Internet: www.nicor.com.

Nicor struggled in the second half of 2008. Most recently, the company posted earnings of $1.05 a share in the fourth quarter, which beat our estimate but still fell short of the prior-year tally. Rising costs coupled with the weak economic environment weighed on GAS' performance. As a result, annual share net fell below 2007's mark of $2.98. Nicor continues to be pressured by higher operating costs.

The company awaits a decision for a rate case filed with the Illinois Commerce Commission (ICC). Given rising expenditures, the utility filed a case for an overall increase in rates. Nicor seeks to raise its rate base by $140.4 million to reflect a return of equity of 11.15%. The new rate would allow the company to better adjust to the current market conditions. In response, the ICC proposed a base increase of $68.8 million, which reflects a cost of equity of 10.17%. The proposal also includes two rate mechanisms focused on energy efficiency. Management is in the process of responding to this offer. After this, Nicor and the ICC will move toward a final decision, which should be announced this month. Accordingly, we recommend investors monitor this situation since it will likely have a heavy bearing on this equity's performance going forward.

We have lowered our estimates for 2009. We look for the bottom line to come in at about $2.50 a share, which is near the proposed base by the ICC. This estimate assumes normal weather and is supported by this utility's steady cash flow. However, if the rate case is approved, our estimates may prove to be conservative.

We are introducing our expectations for 2010. We look for the top and bottom lines to bounce back next year. The shipping business should begin to strengthen over this time frame. Accordingly, we estimate earnings of $2.90 a share.

This stock is ranked 3 (Average) for Timeliness. Nicor's prospects are somewhat ill-defined, given the pending rate case. Thus, we recommend most investors take a wait-and-see approach. However, income-oriented accounts should note that this issue offers an attractive dividend yield, which is above the average for a natural gas utility.

Richard Gallagher *March 13, 2009*

(A) Based on primary earnings thru. '96, then diluted. Excl. nonrecurring gains/(loss): '97, 6¢; '98, 11¢; '99, 5¢; '00, ($1.96); '01, 16¢; '03, (27¢); '04, (52¢); '05, 80¢; '06, (17¢); '07 (13¢). Excl. items from discontinued ops.: '93, 4¢; '96, 30¢. Next egs. report due early May. (B) Dividends historically paid mid February, May, August, November. ■ Dividend reinvestment plan available. (C) In millions.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	75

N.W. NAT'L GAS NYSE-NWN

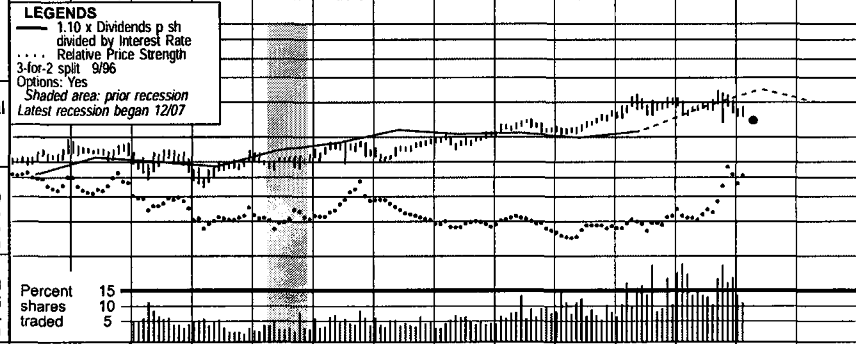
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
38.95	14.3	(Trailing: 15.1 Median: 16.0)	1.39	4.2%	VALUE LINE

TIMELINESS **2** Raised 2/20/09
SAFETY **1** Raised 3/18/05
TECHNICAL **2** Raised 3/6/09
BETA .60 (1.00 = Market)

High:	30.8	27.9	27.5	26.8	30.7	31.3	34.1	39.6	43.7	52.8	55.2	45.7
Low:	24.3	19.5	17.8	21.7	23.5	24.0	27.5	32.4	32.8	39.8	37.7	38.8

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.10 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 9/96
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+80%)	19%
Low	55	(+40%)	12%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	1	0	0	0	0	0	0
Options	0	0	1	0	1	2	0	1	0
to Sell	0	0	1	0	1	2	0	2	0

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	77	78	65
to Sell	92	71	74
Hld's(000)	16772	16947	16310

Percent shares traded 15 10 5

% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	0.7	-44.9
3 yr.	32.4	-44.1
5 yr.	53.5	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
18.15	18.30	16.02	16.86	15.82	16.77	18.17	21.09	25.78	25.07	23.57	25.69	33.01	37.20	39.13	39.17	*39.60*	*41.50*	Revenues per sh	*48.20*
3.74	3.50	3.41	3.86	3.72	3.24	3.72	3.68	3.86	3.65	3.85	3.92	4.34	4.76	5.41	5.29	*5.60*	*5.85*	"Cash Flow" per sh	*6.75*
1.74	1.63	1.61	1.97	1.76	1.02	1.70	1.79	1.88	1.62	1.76	1.86	2.11	2.35	2.76	2.58	*2.75*	*2.85*	Earnings per sh A	*3.45*
1.17	1.17	1.18	1.20	1.21	1.22	1.23	1.24	1.25	1.26	1.27	1.30	1.32	1.39	1.44	1.52	*1.58*	*1.66*	Div'ds Decl'd per sh B■	*2.00*
3.61	4.23	3.02	3.70	5.07	4.02	4.78	3.46	3.23	3.11	4.90	5.52	3.48	3.56	4.48	4.15	*4.50*	*4.50*	Cap'l Spending per sh	*4.50*
13.08	13.63	14.55	15.37	16.02	16.59	17.12	17.93	18.56	18.88	19.52	20.64	21.28	22.01	22.52	23.70	*24.90*	*26.10*	Book Value per sh	*30.50*
19.77	20.13	22.24	22.56	22.86	24.85	25.09	25.23	25.23	25.59	25.94	27.55	27.58	27.24	26.41	26.50	*26.50*	*26.50*	Common Shs Outst'g C	*28.00*
12.9	13.0	12.9	11.7	14.4	26.7	14.5	12.4	12.9	17.2	15.8	16.7	17.0	15.9	16.7	17.7	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*18.0*
.76	.85	.86	.73	.83	1.39	.83	.81	.66	.94	.90	.88	.91	.86	.89	1.14	*estimates*		Relative P/E Ratio	*1.20*
5.2%	5.5%	5.7%	5.2%	4.8%	4.5%	5.0%	5.6%	5.1%	4.5%	4.6%	4.2%	3.7%	3.7%	3.1%	3.3%			Avg Ann'l Div'd Yield	*3.2%*

CAPITAL STRUCTURE as of 12/31/08
Total Debt $760.0 mill. Due in 5 Yrs $259.8 mill.
LT Debt $512.0 mill. LT Interest $37.0 mill.

(Total interest coverage: 4.0x)

Pension Assets-12/07 $241 mill.
Oblig. $260 mill.
Pfd Stock None

Common Stock 26.5 mill. shares

MARKET CAP $1.0 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
455.8	532.1	650.3	641.4	611.3	707.6	910.5	1013.2	1033.2	1037.9	*1050*	*1100*	Revenues ($mill)	*1350*
44.9	47.8	50.2	43.8	46.0	50.6	58.1	65.2	74.5	68.5	*73.0*	*75.5*	Net Profit ($mill)	*96.5*
35.4%	35.9%	35.4%	34.9%	33.7%	34.4%	36.0%	36.3%	37.2%	36.9%	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
9.9%	9.0%	7.7%	6.8%	7.5%	7.1%	6.4%	6.4%	7.2%	6.6%	*7.0%*	*6.9%*	Net Profit Margin	*7.2%*
46.0%	45.1%	43.0%	47.6%	49.7%	46.0%	47.0%	46.3%	46.3%	44.9%	*47%*	*47%*	Long-Term Debt Ratio	*47%*
49.9%	50.9%	53.2%	51.5%	50.3%	54.0%	53.0%	53.7%	53.7%	55.1%	*53%*	*53%*	Common Equity Ratio	*53%*
861.5	887.8	880.5	937.3	1006.6	1052.5	1108.4	1116.5	1106.8	1140.4	*1180*	*1225*	Total Capital ($mill)	*1400*
895.9	934.0	965.0	995.6	1205.9	1318.4	1373.4	1425.1	1495.9	1549.0	*1600*	*1660*	Net Plant ($mill)	*1900*
6.8%	6.7%	6.9%	5.9%	5.7%	5.9%	6.5%	7.1%	8.5%	8.0%	*8.0%*	*8.0%*	Return on Total Cap'l	*8.0%*
9.7%	9.8%	10.0%	8.9%	9.1%	8.9%	9.9%	10.9%	12.5%	11.2%	*11.0%*	*11.0%*	Return on Shr. Equity	*11.0%*
9.9%	10.0%	10.2%	8.5%	9.0%	8.9%	9.9%	10.9%	12.5%	11.2%	*11.0%*	*11.0%*	Return on Com Equity	*11.0%*
2.8%	3.1%	3.5%	1.9%	2.6%	2.7%	3.7%	4.5%	6.0%	4.7%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
74%	70%	67%	79%	72%	69%	63%	59%	52%	59%	*57%*	*58%*	All Div'ds to Net Prof	*58%*

CURRENT POSITION ($MILL.)

	2006	2007	12/31/08
Cash Assets	5.8	6.1	6.9
Other	303.0	268.8	474.1
Current Assets	308.8	274.9	481.0
Accts Payable	113.6	119.7	94.4
Debt Due	129.6	148.1	248.0
Other	98.3	122.1	208.9
Current Liab.	341.5	389.9	551.3
Fx. Chg. Cov.	349%	408%	393%

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '12-'14
Revenues	8.5%	8.5%	6.5%
"Cash Flow"	3.0%	5.5%	5.0%
Earnings	3.0%	6.5%	7.0%
Dividends	1.5%	2.0%	5.5%
Book Value	3.5%	3.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	390.4	171.0	114.9	336.9	1013.2
2007	394.1	183.2	124.2	331.7	1033.2
2008	387.7	191.3	109.7	349.2	1037.9
2009	*390*	*200*	*120*	*340*	*1050*
2010	*410*	*210*	*125*	*355*	*1100*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1.48	.07	d.35	1.15	2.35
2007	1.77	.10	d.22	1.11	2.76
2008	1.63	.08	d.38	1.25	2.58
2009	*1.72*	*.10*	*d.34*	*1.27*	*2.75*
2010	*1.75*	*.11*	*d.33*	*1.32*	*2.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.325	.325	.325	.345	1.32
2006	.345	.345	.345	.355	1.39
2007	.355	.355	.355	.375	1.44
2008	.375	.375	.375	.395	1.52
2009	.395				

BUSINESS: Northwest Natural Gas Co. distributes natural gas to 90 communities, 662,000 customers, in Oregon (90% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 2.5 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 55%; commercial, 28%; industrial, gas transportation, and other, 17%. Employs 1,130. Barclays Global owns 6.5% of shares; officers and directors, 1.3% (4/08 proxy). CEO: Gregg S. Kantor. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Telephone: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural's fourth-quarter earnings gain was a bit above normal. In the final period of 2008, the company profited from its gas cost-sharing arrangement in Oregon, where it had lost money in the prior-year period. Operating and maintenance costs declined 12%, year to year, and the Oregon weather normalization clause helped, as well, though it had no effect on 2007 December-period profits. Despite gas cost-sharing profit in the fourth quarter, Northwest lost about $0.11 a share from the arrangement in 2008. Customer growth, though, slowed to 1.6% in 2008, well below the recent average.

Earnings will likely rise nicely in 2009. Northwest guided to a range of $2.55 to $2.70 a share this year, but we think the company will do a bit better. Even though customer growth will probably be modest in 2009, Northwest should continue to garner new accounts from customers switching to gas from other sources of heat. The revised gas cost-sharing system in Oregon should also help, as the company should benefit from gas prices that are now well below last fall; Northwest's gas cost forecast is approved by the Oregon PUC in October. The new arrangement should reduce earnings swings, as Northwest will book only 10% or 20% of the profit or loss on the cost of gas, down from one-third through 2008.

Earnings from present operations will probably rise steadily through 2012-2014. Customer growth will likely continue to exceed the U.S. average of around 1% per year. Oregon's enlightened regulations should protect Northwest from the vagaries of the weather, and Washington will probably institute a weather adjustment clause, as well. Costs should rise at a slower pace than the customer roster. But

Two large projects could significantly boost Northwest's earnings by 2014. If regulators give all necessary approvals, a gas storage project in California and a new gas pipeline in Oregon will come on stream in 2011-2012. Together, they could require over $525 million of investment by Northwest. The company would have to sell some stock, but the projects could add at least $0.35 a share to our forecast.

These top-quality shares have solid risk-adjusted total-return potential.

Sigourney B. Romaine *March 13, 2009*

(A) Diluted earnings per share. Excludes nonrecurring items: '98, $0.15; '00, $0.11; '06, ($0.06); '08, ($0.03). Next earnings report due early May.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	80

PIEDMONT NAT'L. GAS NYSE-PNY

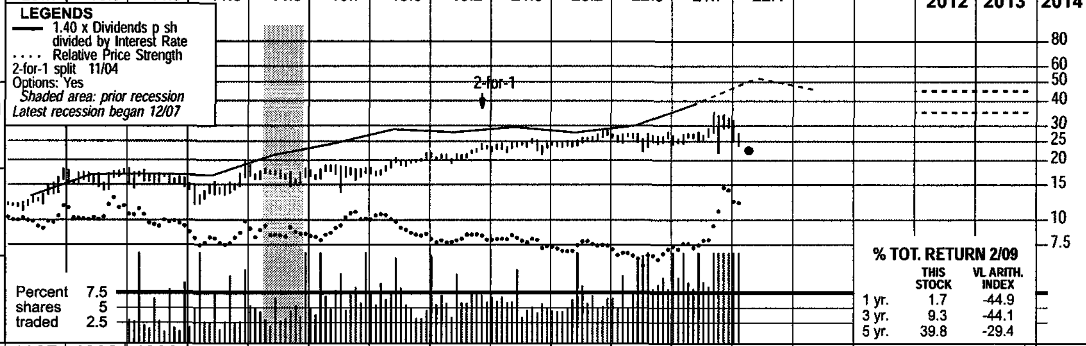
RECENT PRICE	22.46	P/E RATIO	14.0 (Trailing: 15.0 / Median: 18.0)	RELATIVE P/E RATIO	1.36	DIV'D YLD	4.6%	VALUE LINE

TIMELINESS 3 Raised 6/15/07
SAFETY 2 New 7/27/90
TECHNICAL 2 Lowered 1/9/09
BETA .65 (1.00 = Market)

High:	18.1	18.3	19.7	19.0	19.0	22.0	24.3	25.8	28.4	28.0	35.3	32.0
Low:	13.9	14.3	11.8	14.6	13.7	16.6	19.2	21.3	23.2	22.0	21.7	22.4

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.40 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 11/04
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+100%)	23%
Low	35	(+55%)	16%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	1	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	1

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	78	97	82
to Sell	85	77	96
Hld's(000)	36778	36688	35228

% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	1.7	-44.9
3 yr.	9.3	-44.1
5 yr.	39.8	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
10.57	10.82	8.76	11.59	12.84	12.45	10.97	13.01	17.06	12.57	18.14	19.95	22.96	25.80	23.37	28.52	***29.25***	***30.15***	Revenues per sh A	***33.15***
1.14	1.13	1.25	1.49	1.62	1.72	1.70	1.77	1.81	1.81	2.04	2.31	2.43	2.51	2.64	2.77	***2.85***	***3.05***	"Cash Flow" per sh	***3.40***
.73	.68	.73	.84	.93	.98	.93	1.01	1.01	.95	1.11	1.27	1.32	1.28	1.40	1.49	***1.60***	***1.80***	Earnings per sh B	***2.15***
.48	.51	.54	.57	.61	.64	.68	.72	.76	.80	.82	.85	.91	.95	.99	1.03	***1.05***	***1.10***	Div'ds Decl'd per sh C■	***1.25***
1.58	1.95	1.72	1.64	1.52	1.48	1.58	1.65	1.29	1.21	1.16	1.85	2.50	2.74	1.85	2.47	***3.15***	***2.10***	Cap'l Spending per sh	***2.25***
5.45	5.68	6.16	6.53	6.95	7.45	7.86	8.26	8.63	8.91	9.36	11.15	11.53	11.83	11.99	12.11	***12.65***	***13.45***	Book Value per sh D	***15.85***
52.30	53.15	57.67	59.10	60.39	61.48	62.59	63.83	64.93	66.18	67.31	76.67	76.70	74.61	73.23	73.26	***73.50***	***73.50***	Common Shs Outst'g E	***73.00***
15.4	15.7	13.8	13.9	13.6	16.3	17.7	14.3	16.7	18.4	16.7	16.6	17.9	19.2	18.7	18.2	*Bold figures are*		Avg Ann'l P/E Ratio	***18.0***
.91	1.03	.92	.87	.78	.85	1.01	.93	.86	1.01	.95	.88	.95	1.04	.99	1.15	*Value Line*		Relative P/E Ratio	***1.50***
4.3%	4.8%	5.4%	4.9%	4.8%	4.0%	4.1%	5.0%	4.5%	4.6%	4.4%	4.1%	3.8%	3.9%	3.8%	3.8%	*estimates*		Avg Ann'l Div'd Yield	***3.1%***

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
686.5	830.4	1107.9	832.0	1220.8	1529.7	1761.1	1924.6	1711.3	2089.1	***2150***	***2215***	Revenues ($mill) A	***2420***
58.2	64.0	65.5	62.2	74.4	95.2	101.3	97.2	104.4	110.0	***120***	***135***	Net Profit ($mill)	***155***
39.7%	34.7%	34.6%	33.1%	34.8%	35.1%	33.7%	34.2%	33.0%	36.4%	***35.0%***	***35.0%***	Income Tax Rate	***35.0%***
8.5%	7.7%	5.9%	7.5%	6.1%	6.2%	5.8%	5.0%	6.1%	5.3%	***5.5%***	***6.0%***	Net Profit Margin	***6.5%***
46.2%	46.1%	47.6%	43.9%	42.2%	43.6%	41.4%	48.3%	48.4%	47.2%	***51.0%***	***49.5%***	Long-Term Debt Ratio	***47.0%***
53.8%	53.9%	52.4%	56.1%	57.8%	56.4%	58.6%	51.7%	51.6%	52.8%	***49.0%***	***50.5%***	Common Equity Ratio	***53.0%***
914.7	978.4	1069.4	1051.6	1090.2	1514.9	1509.2	1707.9	1703.3	1681.5	***1900***	***1955***	Total Capital ($mill)	***2180***
1047.0	1072.0	1114.7	1158.5	1812.3	1849.8	1939.1	2075.3	2141.5	2240.8	***2250***	***2300***	Net Plant ($mill)	***2450***
8.1%	8.3%	7.9%	7.8%	8.6%	7.8%	8.2%	7.2%	7.8%	8.2%	***7.5%***	***8.5%***	Return on Total Cap'l	***8.5%***
11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	***12.5%***	***13.5%***	Return on Shr. Equity	***13.5%***
11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	***12.5%***	***13.5%***	Return on Com Equity	***13.5%***
3.3%	3.5%	3.0%	1.7%	3.1%	3.7%	3.6%	2.8%	3.5%	3.9%	***4.0%***	***5.0%***	Retained to Com Eq	***6.0%***
72%	71%	75%	83%	74%	66%	68%	74%	70%	69%	***67%***	***62%***	All Div'ds to Net Prof	***57%***

CAPITAL STRUCTURE as of 10/31/08
Total Debt $1230.8 mill. **Due in 5 Yrs** $150.0 mill.
LT Debt $794.3 mill. **LT Interest** $55.5 mill.
(LT interest earned: 4.0x; total interest coverage: 3.7x)

Pension Assets-10/08 $150.3 mill.
Oblig. $143.5 mill.

Pfd Stock None

Common Stock 73,260,672 shs.
as of 12/16/08
MARKET CAP: $1.7 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2006	2007	10/31/08
Cash Assets	8.9	7.5	7.0
Other	467.1	427.8	593.8
Current Assets	476.0	435.3	600.8
Accts Payable	80.3	143.6	132.3
Debt Due	170.0	195.0	436.5
Other	150.1	75.9	112.7
Current Liab.	400.4	424.5	681.5
Fix. Chg. Cov.	323%	309%	341%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	7.5%	10.0%	*4.0%*
"Cash Flow"	5.0%	7.0%	*4.5%*
Earnings	4.5%	6.5%	*7.5%*
Dividends	5.0%	4.5%	*3.5%*
Book Value	5.5%	6.0%	*5.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2006	921.4	483.2	237.9	282.2	1924.7
2007	677.2	531.5	224.4	278.2	1711.3
2008	788.5	634.2	354.7	311.7	2089.1
2009	***815***	***655***	***360***	***320***	***2150***
2010	***830***	***670***	***375***	***340***	***2215***

Fiscal Year Ends	EARNINGS PER SHARE A B F Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2006	.94	.57	d.16	d.08	1.27
2007	.94	.69	d.12	d.11	1.40
2008	1.12	.66	d.10	d.18	1.49
2009	***1.13***	***.68***	***d.10***	***d.11***	***1.60***
2010	***1.15***	***.70***	***d.02***	***d.03***	***1.80***

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.215	.23	.23	.23	.91
2006	.23	.24	.24	.24	.95
2007	.24	.25	.25	.25	.99
2008	.25	.26	.26	.26	1.03
2009	.26				

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 935,724 customers in North Carolina, South Carolina, and Tennessee. 2008 revenue mix: residential (39%), commercial (24%), industrial (12%), other (25%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 73.5% of revenues. '08 deprec. rate: 3.2%. Estimated plant age: 8.7 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 1,833 employees. Officers & directors own about 1.1% of common stock (1/09 proxy). Chairman, CEO, & President: Thomas E. Skains. Inc.: NC. Address: 4720 Piedmont Row Drive, Charlotte, NC 28210. Telephone: 704-364-3120. Internet: www.piedmontng.com.

Piedmont Natural Gas finished fiscal 2008 (ended October 31st) with solid results, despite the difficult economy. Revenues advanced 22% due to higher system throughput volumes, as well as additional customer accounts at the utility segment. However, the bottom-line increase was moderated owing to weaker contributions at the Southstar Energy Services unit. But progress was made.

The January-period bottom line came in slightly above the prior year. The top line benefited from additional customers in the residential, commercial, and conversion markets. Meanwhile, the Hardy Storage facility has begun to gain traction. It recently boosted its contribution to income by more than 20%. Margins were impacted last year because of declining natural gas prices, and a greater gas storage writedown than management expected. More recently, indications are that prices may start to help widen margins and boost earnings contributions from the nonutility portion of PNY's business mix.

Still, economic headwinds may weigh on this year's growth prospects. The past couple of quarters have experienced tapered growth in new accounts. And while these metrics are still relatively steady, the state of the regional economy suggests customer growth may slow further in the months to come. However, cost-cutting efforts ought to offset the slowdown and augur well for the bottom line, contributing to a share-net advance of roughly 7%.

We have introduced our 2010 earnings estimate at $1.80 a share. The continued utilization of Piedmont's Hardy Storage facility should provide a nice avenue for expansion next year. Meanwhile, it's only a matter of time before natural gas prices trend higher. And in the longer term, the Robeson liquefied natural gas storage project is slightly ahead of schedule and on budget to be in service by 2012.

These neutrally ranked shares may appeal to income-oriented accounts. Since our December review, they have declined approximately 21%. They still do not offer much in the way of capital appreciation potential. However, the recent downturn provides a more attractive entry point to this good-yielding stock.

Bryan Fong *March 13, 2009*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring charge: '97, 2¢. Next earnings report due early May.
(C) Dividends historically paid mid-January, April, July, October.
■ Div'd reinvest. plan available; 5% discount.
(D) Includes deferred charges. In 2008: $16.3 million, 22¢/share.
(E) In millions, adjusted for stock split.
(F) Quarters may not add to total due to change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	85

SOUTH JERSEY INDS. NYSE-SJI

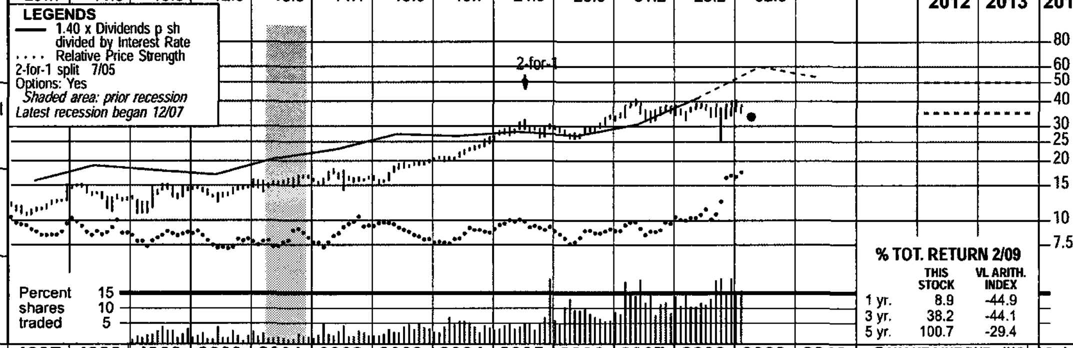
RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
33.42	13.8 (Trailing: 14.7, Median: 14.0)	1.34	3.6%

VALUE LINE

TIMELINESS 2 Raised 12/26/08
SAFETY 2 Lowered 1/4/91
TECHNICAL 2 Raised 3/6/09
BETA .65 (1.00 = Market)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	15.4	15.4	15.1	17.0	18.3	20.3	26.5	32.4	34.3	41.3	40.6	40.8		
Low:	11.0	10.8	12.3	13.8	14.1	15.3	19.7	24.9	25.6	31.2	25.2	32.8		

Target Price Range
2012 | 2013 | 2014



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+50%)	13%
Low	35	(+5%)	5%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	1	0	0	0	0	0	0	0	1
Options	0	0	0	0	0	0	0	0	0
to Sell	0	2	1	0	0	0	0	2	0

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	57	85	71
to Sell	71	58	59
Hld's(000)	17182	17430	17041

% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	8.9	-44.9
3 yr.	38.2	-44.1
5 yr.	100.7	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
17.03	17.45	16.50	16.52	16.18	20.89	17.60	22.43	35.30	20.69	26.34	29.51	31.78	31.76	32.30	32.36	32.80	33.55	Revenues per sh	36.35
1.54	1.35	1.65	1.54	1.60	1.44	1.84	1.95	1.90	2.12	2.24	2.44	2.51	3.51	3.20	3.27	3.50	3.65	"Cash Flow" per sh	4.20
.78	.61	.83	.85	.86	.64	1.01	1.08	1.15	1.22	1.37	1.58	1.71	2.46	2.09	2.27	2.45	2.65	Earnings per sh A	3.10
.72	.72	.72	.72	.72	.72	.72	.73	.74	.75	.78	.82	.86	.92	1.01	1.11	1.20	1.28	Div'ds Decl'd per sh B ■	1.50
1.87	1.93	2.08	2.01	2.30	3.06	2.19	2.21	2.82	3.47	2.36	2.67	3.21	2.51	1.88	2.08	2.25	2.40	Cap'l Spending per sh	2.90
7.17	7.23	7.34	8.03	6.43	6.23	6.74	7.25	7.81	9.67	11.26	12.41	13.50	15.11	16.25	17.33	18.35	19.35	Book Value per sh C	21.20
19.61	21.43	21.44	21.51	21.54	21.56	22.30	23.00	23.72	24.41	26.46	27.76	28.98	29.33	29.61	29.73	30.50	31.00	Common Shs Outst'g D	33.00
15.8	16.1	12.2	13.3	13.8	21.2	13.3	13.0	13.6	13.5	13.3	14.1	16.6	11.9	17.2	15.9	Bold figures are	Value Line	Avg Ann'l P/E Ratio	14.0
.93	1.06	.82	.83	.80	1.10	.76	.85	.70	.74	.76	.74	.88	.64	.91	.98	estimates		Relative P/E Ratio	.95
5.9%	7.4%	7.2%	6.4%	6.1%	5.3%	5.4%	5.2%	4.7%	4.6%	4.3%	3.7%	3.0%	3.2%	2.8%	3.1%			Avg Ann'l Div'd Yield	3.5%

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
392.5	515.9	837.3	505.1	696.8	819.1	921.0	931.4	956.4	962.0	1000	1040	Revenues ($mill)	1200
22.0	24.7	26.8	29.4	34.6	43.0	48.6	72.0	61.8	67.9	75.0	80.0	Net Profit ($mill)	100.0
42.8%	43.1%	42.2%	41.4%	40.6%	40.9%	41.5%	41.3%	41.9%	43.3%	40.0%	40.0%	Income Tax Rate	40.0%
5.6%	4.8%	3.2%	5.8%	5.0%	5.2%	5.3%	7.7%	6.5%	7.1%	7.5%	7.7%	Net Profit Margin	8.3%
53.8%	54.1%	57.0%	53.6%	50.8%	48.7%	44.9%	44.7%	42.7%	39.2%	40.5%	40.5%	Long-Term Debt Ratio	40.5%
37.0%	37.6%	35.9%	46.1%	49.0%	51.0%	55.1%	55.3%	57.3%	60.8%	59.5%	59.5%	Common Equity Ratio	59.5%
405.9	443.5	516.2	512.5	608.4	675.0	710.3	801.1	839.0	848.0	945	1010	Total Capital ($mill)	1175
533.3	562.2	607.0	666.6	748.3	799.9	877.3	920.0	948.9	982.6	1015	1040	Net Plant ($mill)	1220
7.4%	7.4%	6.9%	7.6%	7.3%	7.9%	8.3%	10.1%	8.6%	8.5%	9.0%	9.0%	Return on Total Cap'l	10.0%
11.7%	12.1%	12.1%	12.4%	11.5%	12.4%	12.4%	16.3%	12.8%	13.2%	13.5%	13.5%	Return on Shr. Equity	14.5%
14.6%	14.8%	12.8%	12.5%	11.6%	12.5%	12.4%	16.3%	12.8%	13.2%	13.5%	13.5%	Return on Com Equity	14.5%
4.2%	4.8%	3.5%	4.7%	5.0%	5.9%	6.2%	10.2%	6.7%	6.8%	7.0%	6.5%	Retained to Com Eq	7.0%
72%	67%	76%	62%	57%	52%	50%	37%	48%	49%	49%	50%	All Div'ds to Net Prof	50%

CAPITAL STRUCTURE as of 12/31/08
Total Debt $570.4 mill. **Due in 5 Yrs** $302.7 mill.
LT Debt $332.8 mill. LT Interest $17.0 mill.
(Total interest coverage: 6.0x)

Pension Assets-12/08 $88.3 mill. **Oblig.** $142.7 mill.

Pfd Stock none

Common Stock 29,738,256 common shs. **as of 2/23/09**

MARKET CAP: $1.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2006	2007	12/31/08
Cash Assets	7.9	11.7	5.8
Other	363.8	316.6	429.3
Current Assets	371.7	328.3	435.1
Accts Payable	101.6	101.2	120.2
Debt Due	197.0	118.4	237.6
Other	124.2	108.7	142.1
Current Liab.	422.8	328.3	499.9
Fix. Chg. Cov.	527%	476%	598%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	7.0%	4.0%	2.0%
"Cash Flow"	7.0%	9.0%	4.0%
Earnings	9.5%	12.5%	5.5%
Dividends	2.5%	4.5%	7.0%
Book Value	7.5%	12.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	372.6	153.8	154.7	250.3	931.4
2007	368.4	171.7	156.2	260.1	956.4
2008	348.1	135.8	210.4	267.7	962.0
2009	365	160	200	275	1000
2010	375	170	210	285	1040

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1.06	.20	.51	.69	2.46
2007	1.30	.21	d.05	.63	2.09
2008	1.32	.26	.04	.67	2.27
2009	1.35	.30	.10	.70	2.45
2010	1.40	.35	.15	.75	2.65

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	--	.213	.213	.438	.86
2006	--	.225	.225	.470	.92
2007	--	.245	.245	.515	1.01
2008	--	.270	.270	.568	1.11
2009					

BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, *South Jersey Gas Co., distributes natural gas to* 340,136 customers in New Jersey's southern counties, which covers about 2,500 square miles and includes Atlantic City. Gas revenue mix '08: residential, 46%; commercial, 23%; cogeneration and electric generation, 6%; industrial, 25%. Non-utility operations include: South Jersey Energy, South Jersey Resources Group, Marina Energy, and South Jersey Energy Service Plus. Has 602 employees. Off./dir. control 1.0% of com. shares; Dimensional Fund Advisors, 6.5%; Barclays, 6.1% (3/08 proxy). Chrmn. & CEO: Edward Graham. Incorp.: NJ. Address: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Internet: www.sjindustries.com.

Shares of South Jersey Industries have held up well in recent months. The company reported a solid bottom-line advance for the fourth quarter and full-year 2008. Its nonutility operations posted healthy growth at the Asset Management & Marketing unit. The utility segment has also benefited from increased customer conversions to natural gas and higher margins on off-system sales. The customer base increased by roughly 1.3% in 2008, despite a considerable slowdown in the new housing construction market.

The company has attractive prospects for the coming years. Natural gas remains the fuel of choice in the markets served by South Jersey Gas, where the fuel enjoys a significant price advantage over alternatives. Moreover, healthy performance should continue at South Jersey's nonutility operations. Overall, share earnings will probably advance at a nice clip in 2009.

South Jersey Gas recently filed two petitions with the New Jersey Board of Public Utilities advancing economic stimulus plans. The first accelerates into 2009 and 2010 roughly $100 million of capital spending on various utility infrastructure projects. The company is seeking to recover, and earn a return on, this investment through higher rates. The second petition proposes a $17 million Energy Efficiency Tracker that encourages energy conservation while allowing SJG to earn a competitive return. In addition, South Jersey plans to file a base rate case in early 2010, which will reflect approximately $380 million in capital investment since the last filing.

The company leased out its interest in the Marcellus Shale. It has formed an agreement with an exploration and production company to develop the deep mineral rights on over 21,000 acres of the Marcellus Shale in western Pennsylvania. This move will allow South Jersey to realize the value of this asset without incurring the costs of drilling the acreage itself.

This stock is timely. Earnings and dividend growth should continue to 2012-2014. However, this appears to be partly reflected in the current quotation. The yield on this good-quality issue is also below the average of the gas-utility group.

Michael Napoli, CPA *March 13, 2009*

(A) Based on GAAP EPS through 2006, economic earnings thereafter. GAAP EPS: '07, $2.10; '08, $2.58. Excl. nonrecur. gain (loss): '01, $0.13; '08, ($0.70). Excl gain (losses) from discont. ops.: '99, ($0.02); '00, ($0.04); '01, ($0.02); '02, ($0.04); '03, ($0.09); '05, ($0.02); '06, ($0.02); '07, $0.01. Earnings may not sum due to rounding. Next egs. report due late April/early May. (B) Div'ds paid early Apr., Jul., Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. regulatory assets. In 2008: $270.4 mill., $9.10 per shr. (D) In millions, adj. for split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	95
Earnings Predictability	75

SOUTHWEST GAS NYSE-SWX

RECENT PRICE **18.15** | P/E RATIO **13.9** (Trailing: 12.9; Median: 18.0) | RELATIVE P/E RATIO **1.35** | DIV'D YLD **5.2%** | **VALUE LINE**

TIMELINESS 3 Raised 5/23/08
SAFETY 3 Lowered 1/4/91
TECHNICAL 2 Raised 3/6/09
BETA .70 (1.00 = Market)

2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+120%)	25%
Low	30	(+65%)	17%

Insider Decisions

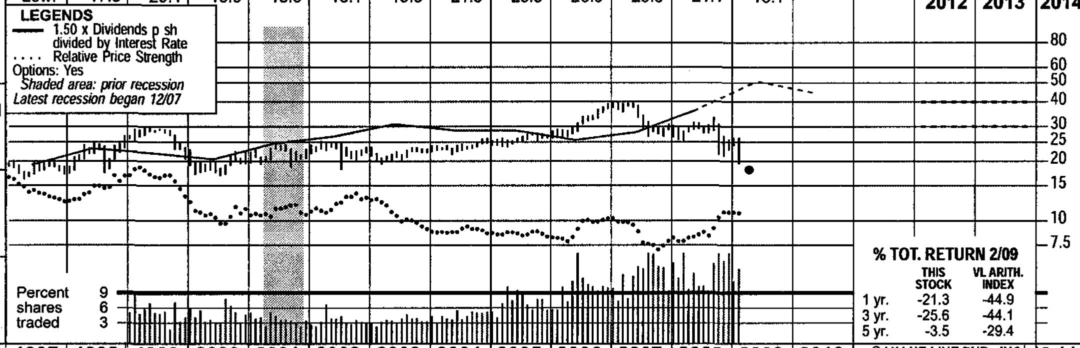
	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	2	1	1	0
Options	0	1	0	0	0	0	0	0	0
to Sell	0	3	0	0	0	2	0	0	0

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	80	85	69
to Sell	88	65	74
Hld's(000)	34496	34150	33669

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	26.9	29.5	23.0	24.7	25.3	23.6	26.2	28.1	39.4	39.9	33.3	26.4
Low:	17.3	20.4	16.9	18.6	18.1	19.3	21.5	23.5	26.0	26.5	21.1	18.1

Target Price Range 2012 | 2013 | 2014



% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-21.3	-44.9
3 yr.	-25.6	-44.1
5 yr.	-3.5	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
25.68	28.16	23.03	24.09	26.73	30.17	30.24	32.61	42.98	39.68	35.96	40.14	43.59	48.47	50.28	48.53	*44.45*	*46.75*	Revenues per sh	*55.00*
3.24	5.09	2.65	3.00	3.85	4.48	4.45	4.57	4.79	5.07	5.11	5.57	5.20	5.97	6.21	5.75	*6.05*	*6.65*	"Cash Flow" per sh	*7.50*
.63	1.22	.10	.25	.77	1.65	1.27	1.21	1.15	1.16	1.13	1.66	1.25	1.98	1.95	1.39	*1.50*	*1.85*	Earnings per sh A	*2.30*
.74	.80	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.86	.90	*.95*	*1.00*	Div'ds Decl'd per sh B■†	*1.15*
5.43	6.64	6.79	8.19	6.19	6.40	7.41	7.04	8.17	8.50	7.03	8.23	7.49	8.27	7.96	6.79	*7.00*	*7.20*	Cap'l Spending per sh	*9.00*
15.96	16.38	14.55	14.20	14.09	15.67	16.31	16.82	17.27	17.91	18.42	19.18	19.10	21.58	22.98	23.48	*24.45*	*25.00*	Book Value per sh	*26.00*
21.00	21.28	24.47	26.73	27.39	30.41	30.99	31.71	32.49	33.29	34.23	36.79	39.33	41.77	42.81	44.19	*45.00*	*46.00*	Common Shs Outst'g C	*50.00*
26.5	14.0	NMF	NMF	24.1	13.2	21.1	16.0	19.0	19.9	19.2	14.3	20.6	15.9	17.3	20.3	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*15.0*
1.57	.92	NMF	NMF	1.39	.69	1.20	1.04	.97	1.09	1.09	.76	1.10	.86	.92	1.25		*estimates*	Relative P/E Ratio	*1.00*
4.4%	4.7%	5.4%	4.7%	4.4%	3.8%	3.1%	4.2%	3.8%	3.6%	3.8%	3.5%	3.2%	2.6%	2.6%	3.2%			Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 12/31/08

Total Debt $1348.3 mill. **Due in 5 Yrs** $624.0 mill.
LT Debt $1285.5 mill. **LT Interest** $90.0 mill.
(Total interest coverage: 2.1x)
Leases, Uncapitalized Annual rentals $6.0 mill.
Pension Assets-12/08 $342.9 mill. **Oblig.** $558.9 mill.
Pfd Stock None

Common Stock 44,436,610 shs. as of 2/17/09

MARKET CAP: $800 million (Small Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
936.9	1034.1	1396.7	1320.9	1231.0	1477.1	1714.3	2024.7	2152.1	2144.7	*2000*	*2150*	Revenues ($mill)	*2750*
39.3	38.3	37.2	38.6	38.5	58.9	48.1	80.5	83.2	61.0	*67.5*	*85.0*	Net Profit ($mill)	*115*
35.5%	26.2%	34.5%	32.8%	30.5%	34.8%	29.7%	37.3%	36.5%	40.1%	*38.0%*	*38.0%*	Income Tax Rate	*36.0%*
4.2%	3.7%	2.7%	2.9%	3.1%	4.0%	2.8%	4.0%	3.9%	2.8%	*3.4%*	*4.0%*	Net Profit Margin	*4.2%*
60.3%	60.2%	56.2%	62.5%	66.0%	64.2%	63.8%	60.6%	58.1%	55.3%	*53.5%*	*52.5%*	Long-Term Debt Ratio	*51.0%*
35.5%	35.8%	39.6%	34.1%	34.0%	35.8%	36.2%	39.4%	41.9%	44.7%	*46.5%*	*47.5%*	Common Equity Ratio	*49.0%*
1424.7	1489.9	1417.6	1748.3	1851.6	1968.6	2076.0	2287.8	2349.7	2323.3	*2375*	*2425*	Total Capital ($mill)	*2650*
1581.1	1686.1	1825.6	1979.5	2175.7	2336.0	2489.1	2668.1	2845.3	2983.3	*3100*	*3250*	Net Plant ($mill)	*3700*
4.8%	4.6%	5.1%	4.3%	4.2%	5.0%	4.3%	5.5%	5.5%	4.5%	*4.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
7.0%	6.5%	6.0%	5.9%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	*6.0%*	*7.5%*	Return on Shr. Equity	*9.0%*
7.8%	7.2%	6.6%	6.5%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	*6.0%*	*7.5%*	Return on Com Equity	*9.0%*
2.8%	2.4%	1.9%	1.9%	1.7%	4.3%	2.2%	5.2%	4.8%	2.1%	*2.5%*	*3.5%*	Retained to Com Eq	*4.5%*
64%	67%	71%	70%	72%	49%	65%	42%	44%	63%	*63%*	*54%*	All Div'ds to Net Prof	*50%*

CURRENT POSITION ($MILL.)	2006	2007	12/31/08
Cash Assets	18.8	32.0	26.4
Other	482.8	470.5	411.7
Current Assets	501.6	502.5	438.1
Accts Payable	265.7	220.7	191.4
Debt Due	27.5	47.1	62.8
Other	202.9	260.1	255.7
Current Liab.	496.1	527.9	509.9
Fix. Chg. Cov.	220%	229%	224%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	7.0%	4.5%	2.0%
"Cash Flow"	6.0%	4.0%	4.0%
Earnings	16.5%	8.0%	4.5%
Dividends	--	.5%	5.0%
Book Value	4.0%	4.0%	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	676.9	430.9	351.8	565.1	2024.7
2007	793.7	426.6	371.5	560.3	2152.1
2008	813.6	447.3	374.4	509.4	2144.7
2009	*790*	*400*	*310*	*500*	*2000*
2010	*810*	*440*	*350*	*550*	*2150*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1.11	.02	d.26	1.11	1.98
2007	1.17	d.01	d.22	1.01	1.95
2008	1.14	d.06	d.38	.71	1.39
2009	*1.00*	*d.05*	*d.35*	*.90*	*1.50*
2010	*1.05*	*Nil*	*d.30*	*1.10*	*1.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.205	.205	.205	.205	.82
2006	.205	.205	.205	.205	.82
2007	.205	.215	.215	.215	.85
2008	.215	.225	.225	.225	.89
2009	.225	.238			

BUSINESS: Southwest Gas Corporation is a regulated gas distributor serving approximately 1.8 million customers in sections of Arizona, Nevada, and California. Comprised of two business segments: natural gas operations and construction services. 2008 margin mix: residential and small commercial, 86%; large commercial and industrial, 5%; transportation, 9%. Total throughput: 2.4 billion therms. Sold PriMerit Bank, 7/96. Has 4,732 employees. Off. & Dir. own 1.8% of common stock; T. Rowe Price Associates, Inc., 6.7%; GAMCO Investors, Inc., 5.8% (3/08 Proxy). Chairman: James J. Kropid. Chief Executive Officer: Jeffrey W. Shaw. Inc.: California. Address: 5241 Spring Mountain Road, Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Shares of Southwest Gas have traded lower in the past six months. Share earnings for 2008 came in well below the prior-year tally. Customer growth dropped to its lowest level in over two decades, owing to the prolonged housing slowdown in the Southwest. This has also hurt performance at construction subsidiary NPL. Looking forward, the business environment will probably remain challenging in 2009. Thus, we anticipate unimpressive results for the current year, too. Operating performance may well improve in 2010, assuming success at controlling costs and an economic rebound.

The company has announced two rate case settlements. In Arizona, Southwest Gas was granted an annual rate increase of $33.5 million, which was somewhat less than the $50.2 million SWX had been seeking. Elsewhere, higher rates in California became effective in January. Looking ahead, Southwest is preparing to file a rate case in Nevada during the second quarter. The company's focus on obtaining rate relief and improving rate design is important, as it depends upon such improved revenue increases to help it cope with higher expenses.

Southwest Gas has announced a dividend increase. Starting in June, the quarterly dividend will be $0.2375 per share, almost 6% higher than the most recent payout. This follows similar increases in the past two years. This pattern is encouraging, and may well continue going forward.

Investors should be mindful of several caveats. Warmer-than-normal temperatures during the winter months can hinder profitability at Southwest Gas. Further efforts to expand operations would probably be accompanied by greater operating costs, too. Moreover, insufficient, or lagging, rate relief can hurt performance.

These shares are not a standout for the coming six to 12 months. Market conditions will likely continue to stymie growth at Southwest Gas in the near term. Looking further out, we anticipate higher earnings by 2012-2014. Moreover, this issue's healthy dividend yield may appeal to income-oriented investors. From the current quotation, this stock has good total return potential for a utility.

Michael Napoli, CPA *March 13, 2009*

(A) Based on avg. shares outstand. thru. '96, then diluted. Excl. nonrec. gains (losses): '93, 8¢; '97, 16¢; '02, (10¢); '05, (11¢); '06, 7¢. Incl. asset writedown: '93, 44¢. Excl. loss from disc. ops.: '95, 75¢. Totals may not sum due to rounding. Next egs. report due early May.
(B) Dividends historically paid early March, June, September, December. ■† Div'd reinvestment and stock purchase plan avail. (C) In millions.

Company's Financial Strength	B
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	70

WGL HOLDINGS NYSE-WGL

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
28.99	11.6 (Trailing: 11.5 Median: 15.0)	1.13	5.0%

VALUE LINE

TIMELINESS **2** Raised 2/13/09
SAFETY **1** Raised 4/2/93
TECHNICAL **2** Raised 3/6/09
BETA .65 (1.00 = Market)

High:	30.8	29.4	31.5	30.5	29.5	28.8	31.4	34.8	33.6	35.9	37.1	35.5
Low:	23.1	21.0	21.8	25.3	19.3	23.2	26.7	28.8	27.0	29.8	22.4	28.9

2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	55%	15%
Low	35	20%	9%

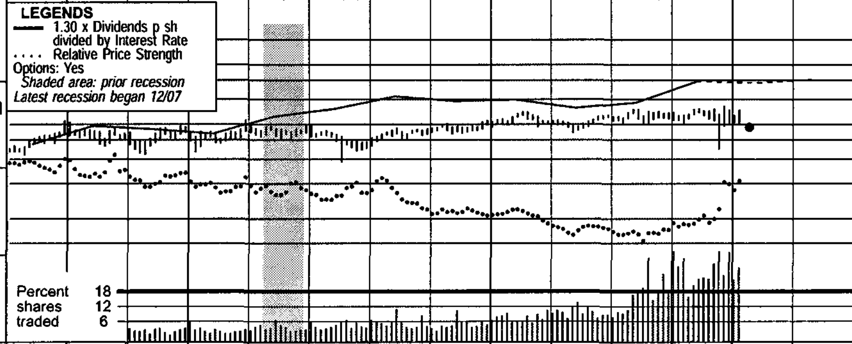
Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	1	0	0	0	0	0	0	0
Options	0	5	1	0	0	2	0	4	0
to Sell	0	7	1	0	0	2	0	4	0

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	106	95	83
to Sell	89	100	119
Hld's(000)	35559	34195	32939

Percent shares traded 18 12 6



Target Price Range 2012 | 2013 | 2014
80 60 50 40 30 25 20 15 10 7.5

% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	1.8	-44.9
3 yr.	12.3	-44.1
5 yr.	30.2	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
21.55	21.69	19.30	22.19	24.16	23.74	20.92	22.19	29.80	32.63	42.45	42.93	44.94	53.96	53.51	52.65	**53.50**	**54.60**	Revenues per sh A	**57.90**
2.25	2.43	2.51	2.93	3.02	2.79	2.74	3.20	3.24	2.63	4.00	3.87	3.97	3.89	3.89	4.34	**4.40**	**4.45**	"Cash Flow" per sh	**4.70**
1.31	1.42	1.45	1.85	1.85	1.54	1.47	1.79	1.88	1.14	2.30	1.98	2.13	1.94	2.10	2.44	**2.50**	**2.55**	Earnings per sh B	**2.75**
1.09	1.11	1.12	1.14	1.17	1.20	1.22	1.24	1.26	1.27	1.28	1.30	1.32	1.35	1.37	1.41	**1.45**	**1.50**	Div'ds Decl'd per sh C■	**1.60**
2.43	2.84	2.63	2.85	3.20	3.62	3.42	2.67	2.68	3.34	2.65	2.33	2.32	3.27	3.33	2.70	**3.00**	**3.00**	Cap'l Spending per sh	**2.50**
11.04	11.51	11.95	12.79	13.48	13.86	14.72	15.31	16.24	15.78	16.25	16.95	17.80	18.86	19.83	20.99	**22.05**	**23.10**	Book Value per sh D	**26.45**
41.50	42.19	42.93	43.70	43.70	43.84	46.47	46.47	48.54	48.56	48.63	48.67	48.65	48.89	49.45	49.92	**50.00**	**50.00**	Common Shs Outst'g E	**50.00**
15.6	14.0	12.7	11.5	12.7	17.2	17.3	14.6	14.7	23.1	11.1	14.2	14.7	15.5	15.6	13.7	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**15.0**
.92	.92	.85	.72	.73	.89	.99	.95	.75	1.26	.63	.75	.78	.84	.82	.85		*estimates*	Relative P/E Ratio	**1.00**
5.3%	5.6%	6.1%	5.4%	5.0%	4.5%	4.8%	4.8%	4.6%	4.8%	5.0%	4.6%	4.2%	4.5%	4.2%	4.2%			Avg Ann'l Div'd Yield	**4.2%**

CAPITAL STRUCTURE as of 12/31/08
Total Debt $1073.0 mill. Due in 5 Yrs $264.5 mill.
LT Debt $657.7 mill. LT Interest $37.4 mill.
(LT interest earned: 5.9x; total interest coverage: 5.2x)
Pension Assets-9/08 $588.2 mill. Oblig. $590.5 mill.
Preferred Stock $28.2 mill. Pfd. Div'd $1.3 mill.

Common Stock 50,124,429 shs. as of 1/31/09

MARKET CAP: $1.5 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
972.1	1031.1	1446.5	1584.8	2064.2	2089.6	2186.3	2637.9	2646.0	2628.2	**2675**	**2730**	Revenues ($mill) A	**2895**
68.8	84.6	89.9	55.7	112.3	98.0	104.8	96.0	102.9	122.9	**125**	**130**	Net Profit ($mill)	**140**
36.0%	36.1%	39.6%	34.0%	38.0%	38.2%	37.4%	39.0%	39.1%	37.1%	**37.0%**	**37.0%**	Income Tax Rate	**38.0%**
7.1%	8.2%	6.2%	3.5%	5.4%	4.7%	4.8%	3.6%	3.9%	4.7%	**4.7%**	**4.7%**	Net Profit Margin	**4.8%**
41.5%	43.1%	41.7%	45.7%	43.8%	40.9%	39.5%	37.8%	37.9%	35.9%	**36.5%**	**35.5%**	Long-Term Debt Ratio	**34.0%**
56.1%	54.8%	56.3%	52.4%	54.3%	57.2%	58.6%	60.4%	60.3%	62.4%	**62.0%**	**63.0%**	Common Equity Ratio	**64.5%**
1218.5	1299.2	1400.8	1462.5	1454.9	1443.6	1478.1	1526.1	1625.4	1679.5	**1780**	**1835**	Total Capital ($mill)	**2050**
1402.7	1460.3	1519.7	1606.8	1874.9	1915.6	1969.7	2067.9	2150.4	2208.3	**2325**	**2420**	Net Plant ($mill)	**2720**
7.1%	7.9%	7.9%	5.3%	9.1%	8.2%	8.5%	7.6%	7.6%	8.5%	**8.0%**	**8.0%**	Return on Total Cap'l	**8.0%**
9.7%	11.4%	11.0%	7.0%	13.7%	11.5%	11.7%	10.1%	10.2%	11.4%	**11.5%**	**11.0%**	Return on Shr. Equity	**10.5%**
9.9%	11.7%	11.2%	7.2%	14.0%	11.7%	12.0%	10.3%	10.4%	11.6%	**12.0%**	**11.5%**	Return on Com Equity	**11.0%**
1.8%	3.7%	3.8%	NMF	6.2%	4.1%	4.6%	3.2%	3.5%	5.0%	**4.5%**	**4.5%**	Retained to Com Eq	**4.5%**
82%	69%	67%	112%	56%	65%	62%	69%	66%	57%	**57%**	**57%**	All Div'ds to Net Prof	**58%**

CURRENT POSITION ($MILL.)	2007	2008	12/31/08
Cash Assets	4.9	6.2	8.8
Other	568.8	736.1	1066.3
Current Assets	573.7	742.3	1075.1
Accts Payable	216.9	243.1	326.9
Debt Due	205.4	347.0	415.3
Other	134.8	158.4	271.8
Current Liab.	557.1	748.5	1014.0
Fix. Chg. Cov.	432%	490%	500%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	8.5%	9.0%	*1.5%*
"Cash Flow"	3.5%	4.0%	*2.5%*
Earnings	2.0%	4.0%	*4.0%*
Dividends	1.5%	1.5%	*2.5%*
Book Value	4.0%	4.5%	*5.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	902.9	1064.5	346.9	323.6	2637.9
2007	732.9	1119.9	467.5	325.7	2646.0
2008	751.6	1020.0	464.7	391.9	2628.2
2009	821.5	***1024***	***469.5***	***360***	***2675***
2010	***835***	***1040***	***485***	***370***	***2730***

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	.93	1.17	d.01	d.15	1.94
2007	.92	1.27	.22	d.31	2.10
2008	.96	1.66	.06	d.24	2.44
2009	1.03	***1.50***	***.15***	***d.18***	***2.50***
2010	***1.05***	***1.50***	***.15***	***d.15***	***2.55***

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.325	.333	.333	.333	1.32
2006	.333	.338	.338	.338	1.34
2007	.34	.34	.34	.34	1.36
2008	.34	.36	.36	.36	1.42
2009	.36				

BUSINESS: WGL Holdings, Inc. is the parent of Washington Gas Light, a natural gas distributor in Washington, D.C. and adjacent areas of VA and MD to resident'l and comm'l users (1,053,032 meters). Hampshire Gas, *a federally regulated sub., operates an* underground gas-storage facility in WV. Non-regulated subs.: Wash. Gas Energy Svcs. sells and delivers natural gas and provides energy related products in the D.C. metro area; Wash. Gas Energy Sys. designs/installs comm'l heating, ventilating, and air cond. systems. American Century Inv. own 7.1% of common stock; Off./dir. less than 1% (1/09 proxy). Chrmn. & CEO: J.H. DeGraffenreidt. Inc.: D.C. and VA. Addr.: 1100 H St., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

WGL Holdings started fiscal 2009 (began October 1st) on a high note. Its regulated utility business gained roughly 7,500 active metered accounts over the year-ago period. And the retail energy marketing segment's contribution to revenues and earnings got a boost from higher realized margins on the sale of natural gas. These items contributed nicely to the 9% top-line volume advance. Meanwhile, decreased labor and benefit costs, due to outsourcing, benefited margins. However, offsetting factors included a slowing of natural gas and electric volumes owing to a reduced number of customers at the retail energy segment. Still, in all, WGL's bottom line advanced 7.3% over this timeframe.

However, March-interim share net will likely fall short compared to the previous year. Over the past 12 months, WGL has initiated decoupling programs in both Virginia and the DC areas to help minimize the effects of weather and usage on its financial results. Thus, last year's second quarter benefited from increased consumption levels whereas 2008's has not. Moving forward, decoupling creates a smoothing effect on the bottom line, and ought to reduce earnings volatility.

On balance, though, the company ought to see its profits rise roughly 3% this year. The regulated utility segment ought to continue to benefit from additional active meters. However, many in this industry have been experiencing a moderation in new accounts. This stems from the sharp recessionary environment that has pushed up home foreclosures. Furthermore, natural gas consumption patterns may decline throughout all service areas as consumers try to cut monthly spending. Still, with over one million active meters, WGL appears to be in good shape to weather this economic storm.

These high-quality shares have provided a bit of a safe haven, as they have held up better than most stocks since our December review. They are also ranked to outperform the broader market in the coming year. What's more, dividend growth is a hallmark here. On the downside, WGL offers minimal appreciation potential for the coming 3 to 5 years, but this is typical for most utilities.

Bryan Fong *March 13, 2009*

(A) Fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢); '07, (4¢) discontinued operations: '06, (15¢). Qtly egs. may not sum to total, due to change in shares outstanding. Next earnings report due late April. (C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available.
(D) Includes deferred charges and intangibles. '08: $291.3 million, $5.81/sh.
(E) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	75

ATTACHMENT B

ZACKS INVESTMENT RESEARCH
Proven Ratings, Research & Recommendations
Zacks.com Quotes and Research

AGL RESOURCES INC (NYSE)

Scottrade

AGL	28.46	▼-0.16	(-0.56%)	Vol. 229,976	16:02 ET

AGL Resources principal business is the distribution of natural gas to customers in central, northwest, northeast and southeast Georgia and the Chattanooga, Tennessee area through its natural gas distribution subsidiary. AGL's major service area is the ten county metropolitan Atlanta area.

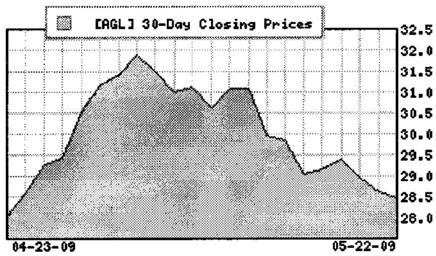
General Information

AGL RESOURCES
Ten Peachtree Place NE
Atlanta, GA 30309
Phone: 404 584-4000
Fax: 404 584-3945
Web: www.aglresources.com
Email: scave@aglresources.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/09
Next EPS Date	07/23/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	28.62
52 Week High	36.42
52 Week Low	24.02
Beta	0.43
20 Day Moving Average	453,827.84
Target Price Consensus	33.75



% Price Change		% Price Change Relative to S&P 500	
4 Week	1.50	4 Week	-2.52
12 Week	2.04	12 Week	-13.39
YTD	-9.22	YTD	-5.30

Share Information		Dividend Information	
Shares Outstanding (millions)	77.09	Dividend Yield	6.04%
		Annual Dividend	$1.72
Market Capitalization (millions)	2,193.90	Payout Ratio	0.55
Short Ratio	3.45	Change in Payout Ratio	-0.02
Last Split Date	12/04/1995	Last Dividend Payout / Amount	05/13/2009 / $0.43

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.22	Current (1=Strong Buy, 5=Strong Sell)	2.20
Current Year EPS Consensus Estimate	2.68	30 Days Ago	2.20
Estimated Long-Term EPS Growth Rate	5.30	60 Days Ago	2.20
Next EPS Report Date	07/23/2009	90 Days Ago	2.17

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	10.62	vs. Previous Year	33.62%	vs. Previous Year	-1.68%
Trailing 12 Months:	9.18	vs. Previous Quarter	59.79%	vs. Previous Quarter:	23.60%
PEG Ratio	1.99				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.24	03/31/09	13.92	03/31/09	3.66

Price/Cash Flow	6.08	12/31/08	12.23	12/31/08	3.20
Price / Sales	0.79	09/30/08	11.74	09/30/08	3.13
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	1.06	03/31/09	0.80	03/31/09	8.53
12/31/08	1.03	12/31/08	0.70	12/31/08	7.41
09/30/08	1.06	09/30/08	0.62	09/30/08	7.44
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	14.84	03/31/09	14.84	03/31/09	22.87
12/31/08	12.46	12/31/08	12.46	12/31/08	21.52
09/30/08	12.43	09/30/08	12.43	09/30/08	22.49
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	3.45	03/31/09	0.95	03/31/09	48.72
12/31/08	3.35	12/31/08	1.01	12/31/08	50.82
09/30/08	2.77	09/30/08	0.97	09/30/08	49.71

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ATMOS ENERGY CORP (NYSE)

Scottrade

ATO	23.91	-0.15	(-0.62%)	Vol. 290,909	16:03 ET

Atmos Energy Corporation distributes and sells natural gas to residential, commercial, industrial, agricultural and other customers. Atmos operates through five divisions in cities, towns and communities in service areas located in Colorado, Georgia, Illinois, Iowa, Kansas, Kentucky, Louisiana, Missouri, South Carolina, Tennessee, Texas and Virginia. The Company has entered into an agreement to sell all of its natural gas utility operations in South Carolina. The Company also transports natural gas for others through its distribution system.

General Information

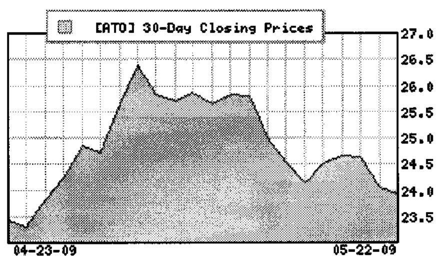
ATMOS ENERGY CP
Three Lincoln Centre 5430 Lbj Freeway
Suite 1800
Dallas, TX 75240
Phone: 972-934-9227
Fax: 972-855-3040
Web: www.atmosenergy.com
Email: InvestorRelations@atmosenergy.com

Industry	UTIL-GAS DISTR
Sector:	Utilities

Fiscal Year End	September
Last Reported Quarter	03/31/09
Next EPS Date	08/04/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	24.06
52 Week High	28.66
52 Week Low	19.68
Beta	0.52
20 Day Moving Average	664,797.38
Target Price Consensus	28.42



% Price Change		% Price Change Relative to S&P 500	
4 Week	2.05	4 Week	-1.99
12 Week	7.75	12 Week	-8.55
YTD	0.89	YTD	4.16

Share Information		Dividend Information	
Shares Outstanding (millions)	91.91	Dividend Yield	5.52%
		Annual Dividend	$1.32
Market Capitalization (millions)	2,197.66	Payout Ratio	0.63
Short Ratio	2.42	Change in Payout Ratio	-0.03
Last Split Date	05/17/1994	Last Dividend Payout / Amount	02/23/2009 / $0.33

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	-0.10	Current (1=Strong Buy, 5=Strong Sell)	2.57
Current Year EPS Consensus Estimate	2.08	30 Days Ago	2.57
Estimated Long-Term EPS Growth Rate	5.80	60 Days Ago	2.57
Next EPS Report Date	08/04/2009	90 Days Ago	2.50

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	11.49	vs. Previous Year	7.26%	vs. Previous Year	-26.67%
Trailing 12 Months:	11.33	vs. Previous Quarter	60.24%	vs. Previous Quarter:	6.12%
PEG Ratio	1.97				

Price Ratios		ROE		ROA	
Price/Book	1.01	03/31/09	9.16	03/31/09	2.93
Price/Cash Flow	5.69	12/31/08	8.73	12/31/08	2.81
Price / Sales	0.33	09/30/08	8.67	09/30/08	2.82
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	1.15	03/31/09	0.90	03/31/09	2.91
12/31/08	0.83	12/31/08	0.55	12/31/08	2.51
09/30/08	1.06	09/30/08	0.59	09/30/08	2.50
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	4.61	03/31/09	4.61	03/31/09	23.70
12/31/08	4.05	12/31/08	4.05	12/31/08	22.70
09/30/08	4.05	09/30/08	4.05	09/30/08	22.65
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	11.66	03/31/09	1.00	03/31/09	49.89
12/31/08	12.20	12/31/08	0.83	12/31/08	45.28
09/30/08	11.99	09/30/08	1.03	09/30/08	50.81

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LACLEDE GROUP INC (NYSE)

LG	29.80	-0.35	(-1.16%)	Vol. 133,326	16:03 ET

The Laclede Group, Inc. is a public utility engaged in the retail distribution and transportation of natural gas. The Company, which is subject to the jurisdiction of the Missouri Public Service Commission, serves the City of St. Louis, St. Louis County, the City of St. Charles, St. Charles County, the town of Arnold, and parts of Franklin, Jefferson, St. Francois, Ste. Genevieve, Iron, Madison and Butler Counties, all in Missouri.

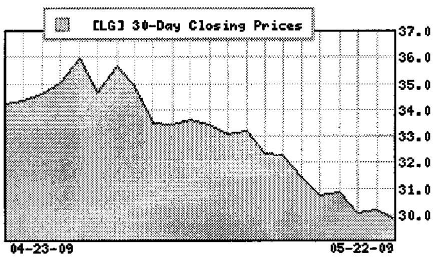
General Information

LACLEDE GRP INC
720 Olive Street
St. Louis, MO 63101
Phone: 314-342-0500
Fax: 314-421-1979
Web: www.thelacledegroup.com
Email: mkullman@lacledegas.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	September
Last Reported Quarter	03/31/09
Next EPS Date	07/24/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	30.15
52 Week High	55.81
52 Week Low	29.75
Beta	0.09
20 Day Moving Average	208,767.66
Target Price Consensus	40



% Price Change		% Price Change Relative to S&P 500	
4 Week	-12.97	4 Week	-16.41
12 Week	-26.29	12 Week	-37.44
YTD	-36.38	YTD	-31.48

Share Information		Dividend Information	
Shares Outstanding (millions)	22.14	Dividend Yield	5.17%
		Annual Dividend	$1.54
Market Capitalization (millions)	659.62	Payout Ratio	0.50
Short Ratio	3.23	Change in Payout Ratio	-0.15
Last Split Date	03/08/1994	Last Dividend Payout / Amount	03/09/2009 / $0.38

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.34	Current (1=Strong Buy, 5=Strong Sell)	3.25
Current Year EPS Consensus Estimate	2.94	30 Days Ago	3.25
Estimated Long-Term EPS Growth Rate	6.50	60 Days Ago	3.25
Next EPS Report Date	07/24/2009	90 Days Ago	3.25

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	10.14	vs. Previous Year	0.72%	vs. Previous Year	-11.85%
Trailing 12 Months:	9.61	vs. Previous Quarter	-1.41%	vs. Previous Quarter:	-2.25%
PEG Ratio	1.56				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.24	03/31/09	13.53	03/31/09	3.89

Price/Cash Flow	6.93	12/31/08	13.74	12/31/08	3.89
Price / Sales	0.29	09/30/08	12.04	09/30/08	3.35
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	1.17	03/31/09	0.95	03/31/09	2.97
12/31/08	1.14	12/31/08	0.74	12/31/08	2.83
09/30/08	1.17	09/30/08	0.69	09/30/08	2.53
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	4.46	03/31/09	4.46	03/31/09	24.11
12/31/08	4.20	12/31/08	4.20	12/31/08	22.98
09/30/08	3.79	09/30/08	3.79	09/30/08	22.14
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	11.31	03/31/09	0.73	03/31/09	42.17
12/31/08	12.61	12/31/08	0.77	12/31/08	43.33
09/30/08	13.28	09/30/08	0.80	09/30/08	44.42

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NEW JERSEY RES (NYSE)					Scottrade
NJR	32.33	▼-0.06	(-0.19%)	Vol. 218,797	16:00 ET

NJ RESOURCES is an exempt energy svcs holding company providing retail & wholesale natural gas & related energy services to customers from the Gulf Coast to New England. Subsidiaries include: (1) N J Natural Gas Co, a natural gas distribution company that provides regulated energy & appliance services to residential, commercial & industrial customers in central & northern N J. (2) NJR Energy Holdings Corp formerly NJR Energy Svcs Corp & (3) NJR Development Corp, a sub-holding company of NJR, which includes the Company's remaining unregulated operating subsidiaries.

General Information

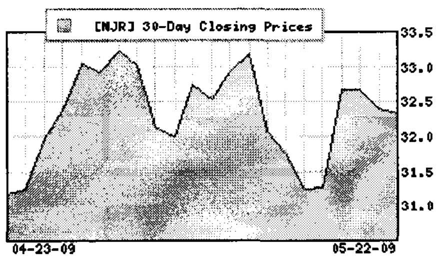
NJ RESOURCES
1415 Wyckoff Road
Wall, NJ 07719
Phone: 732-938-1489
Fax: 732 938-3154
Web: www.njresources.com
Email: investcont@njresources.com

Industry	UTIL-GAS DISTR
Sector:	Utilities

Fiscal Year End	September
Last Reported Quarter	03/31/09
Next EPS Date	07/22/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	32.39
52 Week High	42.37
52 Week Low	21.90
Beta	0.16
20 Day Moving Average	536,252.06
Target Price Consensus	43



% Price Change		% Price Change Relative to S&P 500	
4 Week	3.75	4 Week	-0.35
12 Week	-8.98	12 Week	-22.75
YTD	-17.84	YTD	-18.78

Share Information		Dividend Information	
Shares Outstanding (millions)	42.32	Dividend Yield	3.84%
		Annual Dividend	$1.24
Market Capitalization (millions)	1,368.17	Payout Ratio	0.63
Short Ratio	3.34	Change in Payout Ratio	0.12
Last Split Date	03/04/2008	Last Dividend Payout / Amount	03/11/2009 / $0.31

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.02	Current (1=Strong Buy, 5=Strong Sell)	1.67
Current Year EPS Consensus Estimate	2.39	30 Days Ago	1.67
Estimated Long-Term EPS Growth Rate	8.00	60 Days Ago	1.67
Next EPS Report Date	07/22/2009	90 Days Ago	2.33

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.53	vs. Previous Year	-8.60%	vs. Previous Year	-20.38%
Trailing 12 Months:	16.41	vs. Previous Quarter	123.68%	vs. Previous Quarter:	17.00%
PEG Ratio	1.69				

Price Ratios		ROE		ROA	
Price/Book	1.81	03/31/09	11.73	03/31/09	3.25
Price/Cash Flow	10.20	12/31/08	12.89	12/31/08	3.48
Price / Sales	0.38	09/30/08	13.77	09/30/08	3.74
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	1.17	03/31/09	1.07	03/31/09	2.37
12/31/08	1.17	12/31/08	0.76	12/31/08	2.36
09/30/08	1.24	09/30/08	0.70	09/30/08	2.46
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	5.26	03/31/09	5.26	03/31/09	17.90
12/31/08	3.89	12/31/08	3.89	12/31/08	17.49
09/30/08	4.72	09/30/08	4.72	09/30/08	17.29
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	10.09	03/31/09	0.61	03/31/09	37.74
12/31/08	9.51	12/31/08	0.63	12/31/08	38.48
09/30/08	9.16	09/30/08	0.63	09/30/08	38.50

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NICOR INC (NYSE) Scottrade

GAS	30.90	▼-0.18	(-0.58%)	Vol. 288,557	16:01 ET

Nicor Inc. is a holding company and is a member of the Standard & Poor's 500 Index. Its primary business is Nicor Gas, one of the nation's largest natural gas distribution companies. Nicor owns Tropical Shipping, a containerized shipping business serving the Caribbean region and the Bahamas. In addition, the company owns and has an equity interest in several energy-related businesses.

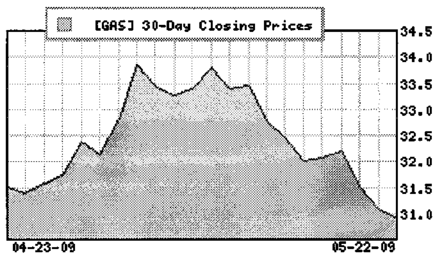
General Information

NICOR INC
1844 Ferry Road
Naperville, IL 60563-9600
Phone: 630-305-9500
Fax: 630-983-9328
Web: www.nicor.com
Email: None

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/09
Next EPS Date	08/10/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	31.08
52 Week High	51.99
52 Week Low	27.50
Beta	0.36
20 Day Moving Average	519,217.91
Target Price Consensus	40.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	-1.94	4 Week	-5.81
12 Week	-2.43	12 Week	-17.19
YTD	-11.05	YTD	-5.73

Share Information		Dividend Information	
Shares Outstanding (millions)	45.20	Dividend Yield	6.02%
		Annual Dividend	$1.86
Market Capitalization (millions)	1,396.80	Payout Ratio	0.69
Short Ratio	4.13	Change in Payout Ratio	-0.05
Last Split Date	04/27/1993	Last Dividend Payout / Amount	03/27/2009 / $0.47

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.42	Current (1=Strong Buy, 5=Strong Sell)	3.40
Current Year EPS Consensus Estimate	2.55	30 Days Ago	3.40
Estimated Long-Term EPS Growth Rate	5.90	60 Days Ago	3.40
Next EPS Report Date	08/10/2009	90 Days Ago	3.40

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.12	vs. Previous Year	5.49%	vs. Previous Year	-30.39%
Trailing 12 Months:	11.53	vs. Previous Quarter	-8.57%	vs. Previous Quarter:	6.73%
PEG Ratio	2.05				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.39	03/31/09	12.46	03/31/09	2.67

Price/Cash Flow	4.51	12/31/08	12.31	12/31/08	2.62
Price / Sales	0.42	09/30/08	13.19	09/30/08	2.87
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	0.78	03/31/09	0.77	03/31/09	3.70
12/31/08	0.80	12/31/08	0.68	12/31/08	3.16
09/30/08	0.76	09/30/08	0.56	09/30/08	3.48
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	5.21	03/31/09	5.21	03/31/09	22.16
12/31/08	4.34	12/31/08	4.34	12/31/08	21.53
09/30/08	4.80	09/30/08	4.80	09/30/08	21.15
Inventory Turnover		**Debt-to-Equity**		***Debt to Capital***	
03/31/09	15.05	03/31/09	0.45	03/31/09	30.91
12/31/08	18.16	12/31/08	0.46	12/31/08	31.52
09/30/08	23.38	09/30/08	0.47	09/30/08	31.92

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NORTHWEST NAT GAS CO (NYSE)

Scottrade

NWN	39.90	-0.13	(-0.32%)	Vol. 173,466	16:03 ET

NW Natural is principally engaged in the distribution of natural gas.The Oregon Public Utility Commission (OPUC) has allocated to NW Natural as its exclusive service area a major portion of western Oregon, including the Portland metropolitan area, most of the fertile Willamette Valley and the coastal area from Astoria to Coos Bay. NW Natural also holds certificates from the Washington Utilities and Transportation Commission (WUTC) granting it exclusive rights to serve portions of three Washington counties bordering the Columbia River.

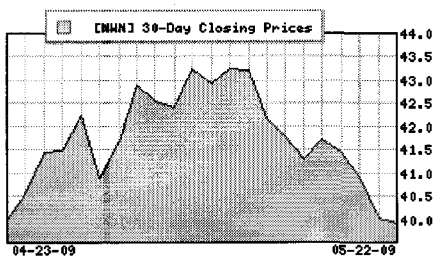
General Information

NORTHWEST NAT G
220 NW Second Avenue
Portland, OR 97209
Phone: 503 226-4211
Fax: 503 273-4824
Web: www.nwnatural.com
Email: Bob.Hess@nwnatural.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/09
Next EPS Date	07/17/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	40.03
52 Week High	55.44
52 Week Low	36.61
Beta	0.29
20 Day Moving Average	170,996.70
Target Price Consensus	51.25



% Price Change		% Price Change Relative to S&P 500	
4 Week	-0.23	4 Week	-4.17
12 Week	-3.20	12 Week	-17.84
YTD	-9.79	YTD	-4.47

Share Information		Dividend Information	
Shares Outstanding (millions)	26.50	Dividend Yield	3.96%
		Annual Dividend	$1.58
Market Capitalization (millions)	1,057.39	Payout Ratio	0.57
Short Ratio	7.62	Change in Payout Ratio	-0.05
Last Split Date	09/09/1996	Last Dividend Payout / Amount	04/28/2009 / $0.40

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.17	Current (1=Strong Buy, 5=Strong Sell)	2.00
Current Year EPS Consensus Estimate	2.77	30 Days Ago	2.00
Estimated Long-Term EPS Growth Rate	6.80	60 Days Ago	2.00
Next EPS Report Date	07/17/2009	90 Days Ago	2.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.39	vs. Previous Year	9.82%	vs. Previous Year	12.81%
Trailing 12 Months:	14.35	vs. Previous Quarter	43.20%	vs. Previous Quarter:	25.24%
PEG Ratio	2.13				
Price Ratios		**ROE**		**ROA**	

Price/Book	1.59	03/31/09	11.69	03/31/09	3.37
Price/Cash Flow	7.44	12/31/08	11.18	12/31/08	3.31
Price / Sales	0.97	09/30/08	10.77	09/30/08	3.29
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	1.03	03/31/09	0.80	03/31/09	6.78
12/31/08	0.87	12/31/08	0.70	12/31/08	6.70
09/30/08	0.69	09/30/08	0.44	09/30/08	6.47
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	10.81	03/31/09	10.81	03/31/09	25.05
12/31/08	10.62	12/31/08	10.62	12/31/08	23.77
09/30/08	10.30	09/30/08	10.30	09/30/08	22.88
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	10.10	03/31/09	0.88	03/31/09	46.93
12/31/08	11.16	12/31/08	0.81	12/31/08	44.90
09/30/08	10.09	09/30/08	0.85	09/30/08	45.84

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PIEDMONT NAT GAS INC (NYSE)

PNY	21.81	-0.28	(-1.27%)	Vol. 335,349	16:02 ET

Piedmont Natural Gas Co, Inc., is an energy and services company engaged in the transportation and sale of natural gas and the sale of propane to residential, commercial and industrial customers in North Carolina, South Carolina and Tennessee. The Company is the second-largest natural gas utility in the southeast. The Company and its non-utility subsidiaries and divisions are also engaged in acquiring, marketing and arranging for the transportation and storage of natural gas for large-volume purchasers, and in the sale of propane to customers in the Company's three-state service area.

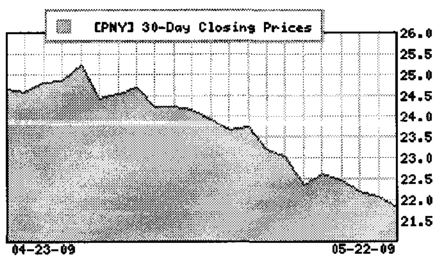
General Information

PIEDMONT NAT GA
4720 Piedmont Row Drive
Charlotte, NC 28210
Phone: 704 364-3120
Fax: 704-365-3849
Web: www.piedmontng.com
Email: investorrelations@piedmontng.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	October
Last Reported Quarter	04/30/09
Next EPS Date	06/08/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	22.09
52 Week High	35.29
52 Week Low	20.52
Beta	0.25
20 Day Moving Average	463,561.66
Target Price Consensus	28.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	-11.52	4 Week	-15.02
12 Week	-10.36	12 Week	-23.92
YTD	-31.13	YTD	-27.83

Share Information		Dividend Information	
Shares Outstanding (millions)	73.48	Dividend Yield	4.95%
		Annual Dividend	$1.08
Market Capitalization (millions)	1,602.69	Payout Ratio	0.00
Short Ratio	9.00	Change in Payout Ratio	0.00
Last Split Date	11/01/2004	Last Dividend Payout / Amount	03/23/2009 / $0.27

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.66	Current (1=Strong Buy, 5=Strong Sell)	2.67
Current Year EPS Consensus Estimate	1.53	30 Days Ago	2.67
Estimated Long-Term EPS Growth Rate	6.50	60 Days Ago	2.67
Next EPS Report Date	06/08/2009	90 Days Ago	2.67

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.22	vs. Previous Year	-1.79%	vs. Previous Year	-1.12%
Trailing 12 Months:	13.89	vs. Previous Quarter	-%	vs. Previous Quarter:	150.08%
PEG Ratio	2.19				

Price Ratios		**ROE**		**ROA**	
Price/Book	1.68	04/30/09	-	04/30/09	-
Price/Cash Flow	7.71	01/31/09	11.70	01/31/09	3.55
Price / Sales	-	10/31/08	11.95	10/31/08	3.67
Current Ratio		**Quick Ratio**		**Operating Margin**	
04/30/09	-	04/30/09	-	04/30/09	-
01/31/09	0.99	01/31/09	0.76	01/31/09	5.22
10/31/08	0.88	10/31/08	0.59	10/31/08	5.27
Net Margin		**Pre-Tax Margin**		**Book Value**	
04/30/09	-	04/30/09	-	04/30/09	-
01/31/09	8.66	01/31/09	8.66	01/31/09	12.98
10/31/08	8.78	10/31/08	8.78	10/31/08	12.11
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
04/30/09	-	04/30/09	-	04/30/09	-
01/31/09	10.50	01/31/09	0.83	01/31/09	45.46
10/31/08	11.18	10/31/08	0.90	10/31/08	47.24

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SOUTH JERSEY INDS INC (NYSE)				Scottrade
SJI	33.20	▾-0.29	(-0.87%)	Vol. 177,091	16:03 ET

South Jersey Inds Inc. is engaged in the business of operating, through subsidiaries, various business enterprises. The company's most significant subsidiary is South Jersey Gas Company (SJG). SJG is a public utility company engaged in the purchase, transmission and sale of natural gas for residential, commercial and industrial use. SJG also makes off-system sales of natural gas on a wholesale basis to various customers on the interstate pipeline system and transports natural gas.

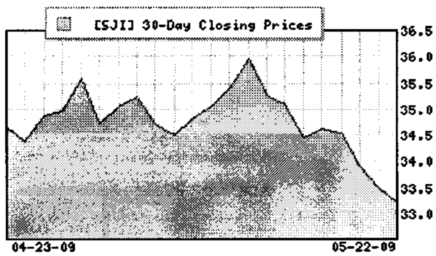
General Information

SOUTH JERSEY IN
1 South Jersey Plaza
Folsom, NJ 08037
Phone: 609 561-9000
Fax: 609 561-8225
Web: www.sjindustries.com
Email: investorrelations@sjindustries.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/09
Next EPS Date	08/06/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	33.49
52 Week High	40.78
52 Week Low	25.19
Beta	0.26
20 Day Moving Average	229,042.00
Target Price Consensus	41.4



% Price Change		**% Price Change Relative to S&P 500**	
4 Week	-4.16	4 Week	-7.95
12 Week	-6.14	12 Week	-20.33
YTD	-16.69	YTD	-11.56

Share Information		**Dividend Information**	
Shares Outstanding (millions)	29.74	Dividend Yield	3.58%
		Annual Dividend	$1.19
Market Capitalization (millions)	987.30	Payout Ratio	0.49
Short Ratio	5.48	Change in Payout Ratio	0.00
Last Split Date	07/01/2005	Last Dividend Payout / Amount	03/06/2009 / $0.30

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	0.27	Current (1=Strong Buy, 5=Strong Sell)	2.50
Current Year EPS Consensus Estimate	2.43	30 Days Ago	2.50
Estimated Long-Term EPS Growth Rate	8.40	60 Days Ago	2.67
Next EPS Report Date	08/06/2009	90 Days Ago	2.67

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	13.64	vs. Previous Year	10.61%	vs. Previous Year	4.06%
Trailing 12 Months:	13.66	vs. Previous Quarter	117.91%	vs. Previous Quarter:	35.30%
PEG Ratio	1.62				

Price Ratios	**ROE**	**ROA**

Price/Book	1.82	03/31/09	14.14	03/31/09	4.30
Price/Cash Flow	9.55	12/31/08	13.56	12/31/08	4.16
Price / Sales	1.01	09/30/08	13.53	09/30/08	4.25
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	0.93	03/31/09	0.74	03/31/09	7.43
12/31/08	0.87	12/31/08	0.52	12/31/08	7.07
09/30/08	0.94	09/30/08	0.45	09/30/08	6.99
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	14.51	03/31/09	14.51	03/31/09	18.20
12/31/08	13.40	12/31/08	13.40	12/31/08	17.33
09/30/08	12.52	09/30/08	12.52	09/30/08	17.32
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	5.73	03/31/09	0.61	03/31/09	38.07
12/31/08	6.46	12/31/08	0.65	12/31/08	39.33
09/30/08	6.67	09/30/08	0.69	09/30/08	41.08

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SOUTHWEST GAS CORP (NYSE)				Scottrade
SWX	19.68	▲0.09	(0.46%)	Vol. 320,937	16:02 ET

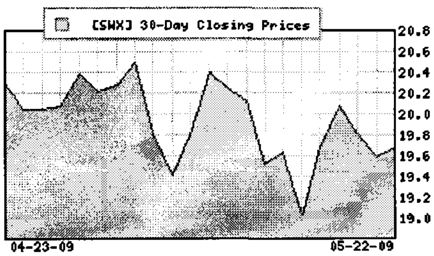
SOUTHWEST GAS CORP. is principally engaged in the business of purchasing,transporting, and distributing natural gas in portions of Arizona, Nevada,and California. The Company also engaged in financial services activities,through PriMerit Bank, Federal Savings Bank (PriMerit or the Bank), a wholly owned subsidiary.

General Information
SOUTHWEST GAS
5241 Spring Mountain Road
P.O. Box 98510
Las Vegas, NV 89193-8510
Phone: 702 876-7237
Fax: 702-876-7037
Web: www.swgas.com
Email: None

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/09
Next EPS Date	08/05/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	19.59
52 Week High	33.29
52 Week Low	17.08
Beta	0.69
20 Day Moving Average	419,823.44
Target Price Consensus	28



% Price Change		% Price Change Relative to S&P 500	
4 Week	-3.01	4 Week	-6.84
12 Week	-5.88	12 Week	-20.12
YTD	-21.97	YTD	-22.80

Share Information		Dividend Information	
Shares Outstanding (millions)	44.58	Dividend Yield	4.83%
		Annual Dividend	$0.95
Market Capitalization (millions)	877.30	Payout Ratio	0.65
Short Ratio	2.23	Change in Payout Ratio	0.12
Last Split Date	N/A	Last Dividend Payout / Amount	05/13/2009 / $0.24

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	-0.05	Current (1=Strong Buy, 5=Strong Sell)	2.60
Current Year EPS Consensus Estimate	1.84	30 Days Ago	2.60
Estimated Long-Term EPS Growth Rate	6.00	60 Days Ago	2.60
Next EPS Report Date	08/05/2009	90 Days Ago	2.60

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	10.71	vs. Previous Year	-1.75%	vs. Previous Year	-15.21%
Trailing 12 Months:	14.16	vs. Previous Quarter	57.75%	vs. Previous Quarter:	35.42%
PEG Ratio	1.79				

Price Ratios		ROE		ROA	
Price/Book	0.81	03/31/09	5.45	03/31/09	1.56

Price/Cash Flow	3.34	12/31/08	5.93	12/31/08	1.69
Price / Sales	0.43	09/30/08	7.18	09/30/08	2.04
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	0.82	03/31/09	0.82	03/31/09	2.81
12/31/08	0.86	12/31/08	0.86	12/31/08	2.84
09/30/08	0.75	09/30/08	0.75	09/30/08	3.32
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	5.09	03/31/09	5.09	03/31/09	24.40
12/31/08	4.75	12/31/08	4.75	12/31/08	23.63
09/30/08	5.37	09/30/08	5.37	09/30/08	23.22
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	-	03/31/09	1.05	03/31/09	51.33
12/31/08	-	12/31/08	1.24	12/31/08	55.33
09/30/08	-	09/30/08	1.20	09/30/08	52.20

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WGL HLDGS INC (NYSE)

Scottrade

WGL	28.83	▼-0.25	(-0.86%)	Vol. 294,657	16:02 ET

WASHINGTON GAS LIGHT CO is a public utility that delivers and sells natural gas to metropolitan Washington, D.C. and adjoining areas in Maryland and Virginia. A distribution subsidiary serves portions of Virginia and West Virginia. The Company has four wholly-owned active subsidiaries that include: Shenandoah Gas Company (Shenandoah) is engaged in the delivery and sale of natural gas at retail in the Shenandoah Valley, including Winchester, Middletown, Strasburg, Stephens City and New Market, Virginia, and Martinsburg, West Virginia.

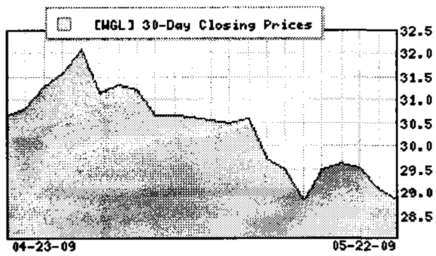
General Information

WGL HLDGS INC
101 Constitution Avenue NW
Washington, DC 20080
Phone: 703 750-2000
Fax: 703 750-4828
Web: www.wglholdings.com
Email: madams@washgas.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	September
Last Reported Quarter	03/31/09
Next EPS Date	08/10/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	29.08
52 Week High	37.08
52 Week Low	22.40
Beta	0.24
20 Day Moving Average	463,851.84
Target Price Consensus	34.67



% Price Change		% Price Change Relative to S&P 500	
4 Week	-6.00	4 Week	-9.72
12 Week	-5.26	12 Week	-19.59
YTD	-11.81	YTD	-9.80

Share Information		Dividend Information	
Shares Outstanding (millions)	50.12	Dividend Yield	5.10%
		Annual Dividend	$1.47
Market Capitalization (millions)	1,445.07	Payout Ratio	0.56
Short Ratio	6.94	Change in Payout Ratio	-0.11
Last Split Date	05/02/1995	Last Dividend Payout / Amount	04/07/2009 / $0.37

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.03	Current (1=Strong Buy, 5=Strong Sell)	2.50
Current Year EPS Consensus Estimate	2.45	30 Days Ago	2.50
Estimated Long-Term EPS Growth Rate	6.70	60 Days Ago	2.50
Next EPS Report Date	08/10/2009	90 Days Ago	2.50

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	11.79	vs. Previous Year	-0.60%	vs. Previous Year	2.04%
Trailing 12 Months:	11.44	vs. Previous Quarter	60.19%	vs. Previous Quarter:	26.71%
PEG Ratio	1.77				

Price Ratios	ROE	ROA

Price/Book	1.26	03/31/09	11.60	03/31/09	3.75
Price/Cash Flow	6.69	12/31/08	11.76	12/31/08	3.79
Price / Sales	0.58	09/30/08	11.60	09/30/08	3.72
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	1.20	03/31/09	1.04	03/31/09	5.08
12/31/08	1.06	12/31/08	0.70	12/31/08	5.11
09/30/08	0.99	09/30/08	0.42	09/30/08	5.09
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	7.58	03/31/09	7.58	03/31/09	22.89
12/31/08	8.04	12/31/08	8.04	12/31/08	21.79
09/30/08	7.08	09/30/08	7.08	09/30/08	20.99
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	8.22	03/31/09	0.57	03/31/09	35.81
12/31/08	7.91	12/31/08	0.60	12/31/08	37.05
09/30/08	8.11	09/30/08	0.58	09/30/08	35.95

ATTACHMENT C

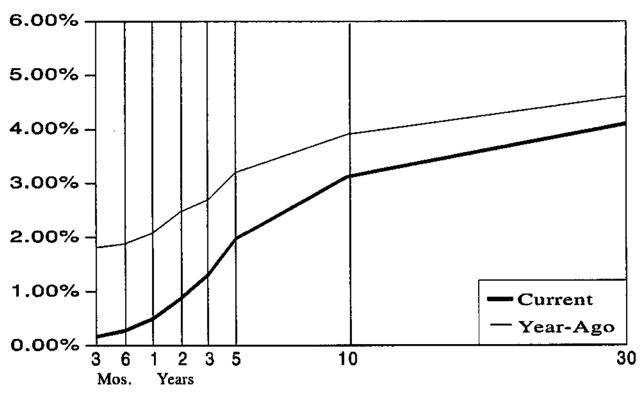
Selected Yields

TAXABLE

	Recent (5/13/09)	3 Months Ago (2/11/09)	Year Ago (5/14/08)
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.32	0.48	2.70
3-month LIBOR	0.88	1.23	2.72
Bank CDs			
6-month	0.73	0.89	1.77
1-year	0.98	1.08	2.05
5-year	1.93	2.37	3.16
U.S. Treasury Securities			
3-month	0.17	0.30	1.82
6-month	0.28	0.45	1.88
1-year	0.50	0.60	2.08
5-year	1.98	1.75	3.20
10-year	3.12	2.75	3.91
10-year (inflation-protected)	1.64	1.60	1.35
30-year	4.10	3.44	4.61
30-year Zero	4.18	3.31	4.71

	Recent (5/13/09)	3 Months Ago (2/11/09)	Year Ago (5/14/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.09	4.02	5.04
FHLMC 6.5% (Gold)	2.38	3.62	5.16
FNMA 6.5%	2.20	3.63	4.90
FNMA ARM	2.78	3.89	4.41
Corporate Bonds			
Financial (10-year) A	6.94	8.09	5.68
Industrial (25/30-year) A	6.19	5.94	6.06
Utility (25/30-year) A	6.01	5.60	6.10
Utility (25/30-year) Baa/BBB	7.57	7.00	6.41
Foreign Bonds (10-Year)			
Canada	3.10	2.94	3.60
Germany	3.34	3.19	4.17
Japan	1.46	1.31	1.68
United Kingdom	3.52	3.61	4.82
Preferred Stocks			
Utility A	6.35	6.01	6.28
Financial A	8.65	11.01	6.75
Financial Adjustable A	5.51	5.51	5.51

Treasury Security Yield Curve



TAX-EXEMPT

	Recent (5/13/09)	3 Months Ago (2/11/09)	Year Ago (5/14/08)
Bond Buyer Indexes			
20-Bond Index (GOs)	4.63	4.96	4.62
25-Bond Index (Revs)	5.57	5.74	5.07
General Obligation Bonds (GOs)			
1-year Aaa	0.43	0.55	1.83
1-year A	1.16	0.65	1.93
5-year Aaa	1.82	1.76	2.97
5-year A	3.24	2.02	3.07
10-year Aaa	2.86	2.84	3.62
10-year A	4.41	3.34	3.83
25/30-year Aaa	4.43	4.71	4.55
25/30-year A	5.91	5.75	4.75
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.96	5.75	4.80
Electric AA	6.06	5.80	4.85
Housing AA	6.36	6.10	5.00
Hospital AA	6.31	6.15	5.05
Toll Road Aaa	6.11	5.85	4.85

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

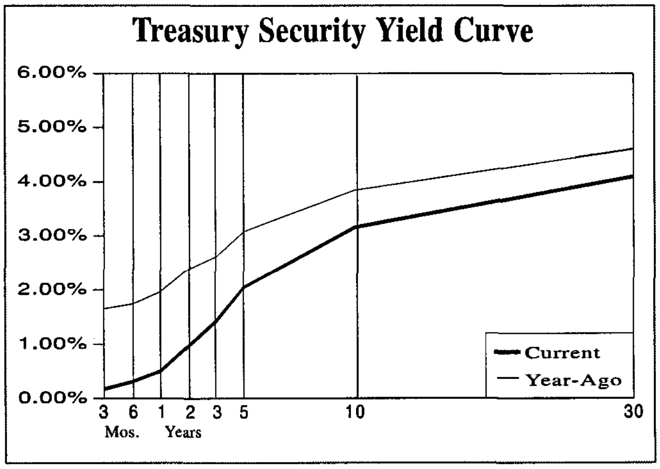
	Recent Levels			Average Levels Over the Last...		
	5/6/09	4/22/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	777464	862387	-84923	731758	706418	385094
Borrowed Reserves	507911	565360	-57449	579211	611473	433308
Net Free/Borrowed Reserves	269553	297027	-27474	152547	94945	-48214

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	4/27/09	4/20/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1576.9	1559.4	17.5	7.3%	12.8%	14.2%
M2 (M1+savings+small time deposits)	8285.2	8243.6	41.6	1.9%	9.5%	8.8%

Selected Yields

	Recent (5/06/09)	3 Months Ago (2/04/09)	Year Ago (5/07/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.40	0.55	2.56
3-month LIBOR	0.97	1.24	2.73
Bank CDs			
6-month	0.79	0.87	1.72
1-year	0.98	1.29	1.99
5-year	1.93	2.41	3.05
U.S. Treasury Securities			
3-month	0.18	0.29	1.66
6-month	0.31	0.40	1.74
1-year	0.50	0.49	1.96
5-year	2.05	1.94	3.08
10-year	3.16	2.94	3.85
10-year (inflation-protected)	1.69	1.78	1.37
30-year	4.10	3.68	4.61
30-year Zero	4.14	3.55	4.68



	Recent (5/06/09)	3 Months Ago (2/04/09)	Year Ago (5/07/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.37	4.28	4.86
FHLMC 6.5% (Gold)	2.91	4.17	5.10
FNMA 6.5%	2.71	4.14	4.84
FNMA ARM	2.78	3.89	4.40
Corporate Bonds			
Financial (10-year) A	7.19	8.03	5.74
Industrial (25/30-year) A	6.31	6.15	6.03
Utility (25/30-year) A	6.10	6.00	6.11
Utility (25/30-year) Baa/BBB	7.54	7.27	6.39
Foreign Bonds (10-Year)			
Canada	3.07	3.12	3.67
Germany	3.24	3.36	4.18
Japan	1.41	1.36	1.67
United Kingdom	3.61	3.77	4.71
Preferred Stocks			
Utility A	6.00	6.02	6.24
Financial A	8.19	10.79	6.73
Financial Adjustable A	5.51	5.51	5.51
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.70	5.16	4.63
25-Bond Index (Revs)	5.57	5.89	5.07
General Obligation Bonds (GOs)			
1-year Aaa	0.43	0.55	1.83
1-year A	1.16	0.65	1.93
5-year Aaa	1.84	1.79	3.03
5-year A	3.25	2.09	3.13
10-year Aaa	2.91	2.90	3.70
10-year A	4.45	3.40	3.90
25/30-year Aaa	4.53	4.82	4.62
25/30-year A	6.05	5.82	4.82
Revenue Bonds (Revs) (25/30-Year)			
Education AA	6.10	5.90	4.90
Electric AA	6.15	6.00	4.95
Housing AA	6.45	6.25	5.05
Hospital AA	6.40	6.20	5.10
Toll Road Aaa	6.20	6.05	4.95

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	4/22/09	4/8/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	862387	804790	57597	733984	671007	356363
Borrowed Reserves	565360	595938	-30578	587381	624561	419423
Net Free/Borrowed Reserves	297027	208852	88175	146604	46446	-63060

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

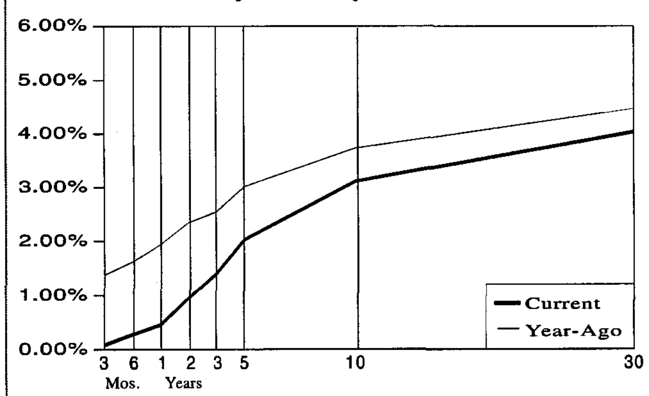
	Recent Levels			Growth Rates Over the Last...		
	4/20/09	4/13/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1559.4	1576.3	-16.9	2.3%	13.7%	13.1%
M2 (M1+savings+small time deposits)	8244.9	8249.3	-4.4	1.0%	7.9%	8.1%

Selected Yields

	Recent (4/29/09)	3 Months Ago (1/28/09)	Year Ago (4/30/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.40	0.45	2.60
3-month LIBOR	1.03	1.17	2.85
Bank CDs			
6-month	0.79	0.88	1.75
1-year	0.98	1.25	1.77
5-year	1.93	2.39	2.96
U.S. Treasury Securities			
3-month	0.09	0.18	1.38
6-month	0.28	0.33	1.62
1-year	0.46	0.47	1.94
5-year	2.03	1.69	3.01
10-year	3.11	2.67	3.73
10-year (inflation-protected)	1.57	1.78	1.35
30-year	4.03	3.42	4.47
30-year Zero	4.05	3.29	4.54

	Recent (4/29/09)	3 Months Ago (1/28/09)	Year Ago (4/30/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.30	3.90	5.02
FHLMC 6.5% (Gold)	2.61	3.50	5.21
FNMA 6.5%	2.45	3.50	4.93
FNMA ARM	3.15	4.27	4.40
Corporate Bonds			
Financial (10-year) A	7.84	7.96	5.91
Industrial (25/30-year) A	6.41	6.18	6.00
Utility (25/30-year) A	6.33	6.10	6.12
Utility (25/30-year) Baa/BBB	7.58	7.04	6.31
Foreign Bonds (10-Year)			
Canada	3.08	2.96	3.59
Germany	3.13	3.23	4.12
Japan	1.42	1.27	1.59
United Kingdom	3.46	3.64	4.67
Preferred Stocks			
Utility A	7.53	5.98	6.19
Financial A	8.96	8.89	6.65
Financial Adjustable A	5.50	5.50	5.50

Treasury Security Yield Curve



	Recent (4/29/09)	3 Months Ago (1/28/09)	Year Ago (4/30/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.57	5.13	4.68
25-Bond Index (Revs)	5.49	5.82	5.01
General Obligation Bonds (GOs)			
1-year Aaa	0.54	0.55	1.80
1-year A	1.04	0.65	1.90
5-year Aaa	1.80	1.84	3.00
5-year A	2.23	2.14	3.10
10-year Aaa	3.19	3.00	3.69
10-year A	3.55	3.50	3.90
25/30-year Aaa	4.67	5.05	4.61
25/30-year A	5.11	6.05	4.81
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.80	6.05	4.90
Electric AA	5.90	6.10	4.95
Housing AA	6.20	6.40	5.05
Hospital AA	6.15	6.45	5.10
Toll Road Aaa	5.95	6.15	4.95

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	4/22/09	**4/8/09**	**Change**	**12 Wks.**	**26 Wks.**	**52 Wks.**
Excess Reserves	862392	804794	57598	733986	671008	356363
Borrowed Reserves	565360	595938	-30578	587381	624561	419423
Net Free/Borrowed Reserves	297032	208856	88176	146606	46447	-63060

MONEY SUPPLY

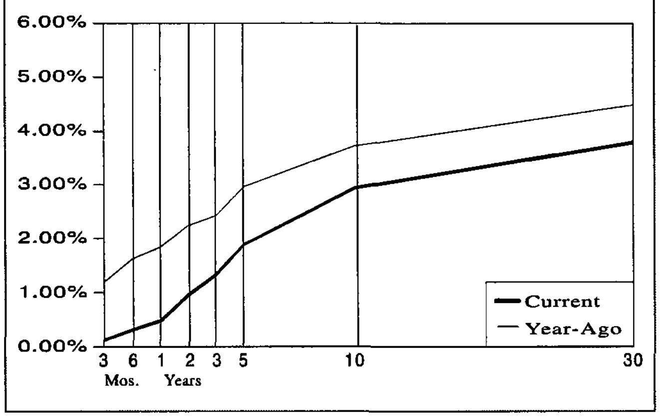
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	4/13/09	**4/6/09**	**Change**	**3 Mos.**	**6 Mos.**	**12 Mos.**
M1 (Currency+demand deposits)	1576.3	1644.4	-68.1	-6.3%	15.4%	14.8%
M2 (M1+savings+small time deposits)	8249.3	8247.7	1.6	3.0%	9.3%	8.3%

Selected Yields

	Recent (4/22/09)	3 Months Ago (1/21/09)	Year Ago (4/23/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.50
Federal Funds	0.00-0.25	0.00-0.25	2.25
Prime Rate	3.25	3.25	5.25
30-day CP (A1/P1)	0.37	0.55	2.78
3-month LIBOR	1.10	1.13	2.92
Bank CDs			
6-month	0.80	1.03	1.75
1-year	0.99	1.34	1.78
5-year	1.93	2.38	2.95
U.S. Treasury Securities			
3-month	0.13	0.11	1.21
6-month	0.32	0.29	1.63
1-year	0.48	0.43	1.84
5-year	1.89	1.61	2.96
10-year	2.94	2.54	3.73
10-year (inflation-protected)	1.59	1.95	1.29
30-year	3.80	3.16	4.49
30-year Zero	3.79	2.94	4.60

Treasury Security Yield Curve



	Recent (4/22/09)	3 Months Ago (1/21/09)	Year Ago (4/23/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.32	3.78	5.11
FHLMC 6.5% (Gold)	2.72	3.53	5.12
FNMA 6.5%	2.58	3.47	4.94
FNMA ARM	3.15	4.25	4.67
Corporate Bonds			
Financial (10-year) A	7.71	7.97	6.03
Industrial (25/30-year) A	6.31	6.05	6.10
Utility (25/30-year) A	6.19	6.03	6.15
Utility (25/30-year) Baa/BBB	7.41	6.66	6.27
Foreign Bonds (10-Year)			
Canada	2.94	2.73	3.67
Germany	3.21	3.00	4.15
Japan	1.44	1.23	1.46
United Kingdom	3.45	3.44	4.67
Preferred Stocks			
Utility A	6.31	6.05	6.03
Financial A	8.98	8.58	6.79
Financial Adjustable A	5.50	5.49	5.50
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.78	4.80	4.61
25-Bond Index (Revs)	5.63	5.72	5.04
General Obligation Bonds (GOs)			
1-year Aaa	0.43	0.48	1.55
1-year A	1.16	0.58	1.65
5-year Aaa	1.73	1.71	2.85
5-year A	3.15	2.00	2.95
10-year Aaa	2.88	2.82	3.54
10-year A	4.43	3.32	3.75
25/30-year Aaa	4.44	4.76	4.53
25/30-year A	5.95	5.76	4.73
Revenue Bonds (Revs) (25/30-Year)			
Education AA	6.00	5.80	4.80
Electric AA	6.10	5.90	4.85
Housing AA	6.40	6.15	4.95
Hospital AA	6.35	6.10	5.00
Toll Road Aaa	6.15	5.95	4.85

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	4/8/09	3/25/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	804800	771271	33529	731287	619127	324505
Borrowed Reserves	595938	604849	-8911	586952	622967	403815
Net Free/Borrowed Reserves	208862	166422	42440	144335	-3841	-79310

MONEY SUPPLY

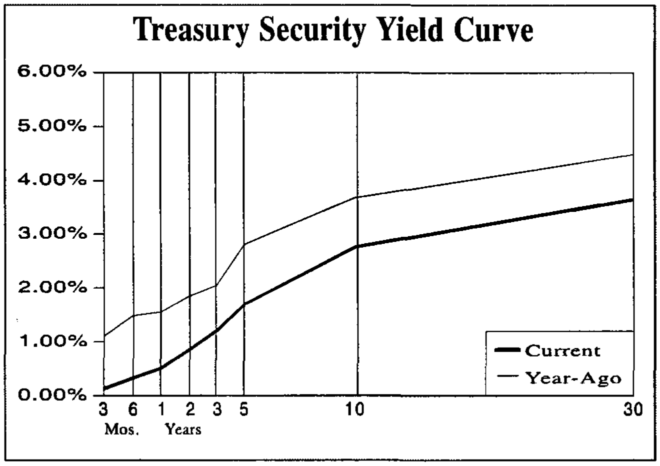
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	4/6/09	3/30/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1641.2	1551.3	89.9	1.0%	26.6%	20.5%
M2 (M1+savings+small time deposits)	8244.7	8308.2	-63.5	3.3%	10.4%	8.2%

Selected Yields

	Recent (4/15/09)	3 Months Ago (1/14/09)	Year Ago (4/16/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.50
Federal Funds	0.00-0.25	0.00-0.25	2.25
Prime Rate	3.25	3.25	5.25
30-day CP (A1/P1)	0.38	0.49	2.56
3-month LIBOR	1.11	1.08	2.73
Bank CDs			
6-month	0.81	1.03	1.76
1-year	1.02	1.34	1.79
5-year	2.01	2.38	2.87
U.S. Treasury Securities			
3-month	0.14	0.09	1.12
6-month	0.33	0.27	1.49
1-year	0.51	0.41	1.56
5-year	1.70	1.35	2.81
10-year	2.76	2.20	3.69
10-year (inflation-protected)	1.43	1.73	1.21
30-year	3.66	2.89	4.49
30-year Zero	3.66	2.75	4.62

	Recent (4/15/09)	3 Months Ago (1/14/09)	Year Ago (4/16/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.39	3.93	4.90
FHLMC 6.5% (Gold)	2.67	3.25	5.14
FNMA 6.5%	2.62	3.30	4.81
FNMA ARM	3.15	4.26	4.66
Corporate Bonds			
Financial (10-year) A	7.61	7.15	6.11
Industrial (25/30-year) A	6.25	5.84	6.12
Utility (25/30-year) A	6.17	5.88	6.28
Utility (25/30-year) Baa/BBB	7.59	6.60	6.40
Foreign Bonds (10-Year)			
Canada	2.94	2.56	3.68
Germany	3.14	2.93	4.04
Japan	1.44	1.27	1.35
United Kingdom	3.26	3.12	4.53
Preferred Stocks			
Utility A	6.36	6.05	6.06
Financial A	7.55	7.76	6.71
Financial Adjustable A	5.49	5.49	5.49
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.92	5.02	4.61
25-Bond Index (Revs)	5.74	5.90	5.04
General Obligation Bonds (GOs)			
1-year Aaa	0.43	0.48	1.55
1-year A	0.53	0.58	1.65
5-year Aaa	1.91	1.76	2.85
5-year A	2.13	2.06	2.95
10-year Aaa	3.09	2.82	3.54
10-year A	3.62	3.32	3.75
25/30-year Aaa	4.71	4.75	4.53
25/30-year A	5.75	5.75	4.73
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.70	5.75	4.80
Electric AA	5.80	5.80	4.85
Housing AA	6.10	6.10	4.95
Hospital AA	6.15	6.15	5.00
Toll Road Aaa	5.85	5.85	4.85



Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

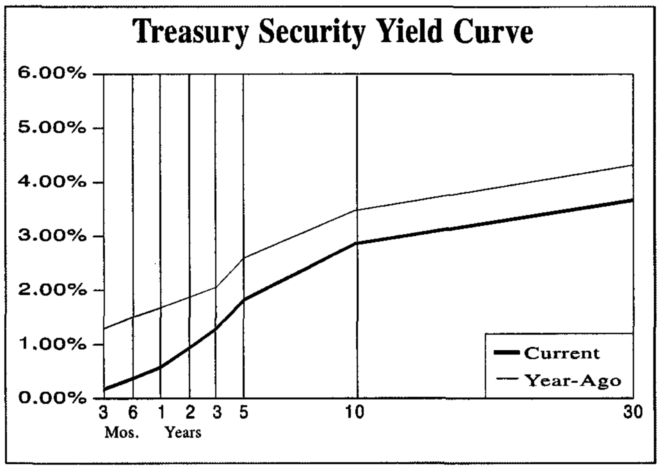
	Recent Levels			Average Levels Over the Last...		
	4/8/09	3/25/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	804805	771269	33536	731288	619127	324505
Borrowed Reserves	595938	604849	-8911	586952	622967	403815
Net Free/Borrowed Reserves	208867	166420	42447	144336	-3840	-79310

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	3/30/09	3/23/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1551.1	1549.4	1.7	-10.7%	8.2%	13.1%
M2 (M1+savings+small time deposits)	8308.0	8336.5	-28.5	7.3%	10.8%	9.1%

Selected Yields

	Recent (4/08/09)	3 Months Ago (1/07/09)	Year Ago (4/09/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.50
Federal Funds	0.00-0.25	0.00-0.25	2.25
Prime Rate	3.25	3.25	5.25
30-day CP (A1/P1)	0.33	0.65	2.63
3-month LIBOR	1.14	1.40	2.72
Bank CDs			
6-month	0.83	1.10	1.76
1-year	1.04	1.41	1.79
5-year	2.05	2.38	2.87
U.S. Treasury Securities			
3-month	0.18	0.09	1.30
6-month	0.37	0.28	1.50
1-year	0.58	0.41	1.68
5-year	1.83	1.66	2.60
10-year	2.86	2.49	3.48
10-year (inflation-protected)	1.53	2.44	1.07
30-year	3.67	3.04	4.32
30-year Zero	3.67	2.87	4.43



	Recent (4/08/09)	3 Months Ago (1/07/09)	Year Ago (4/09/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.40	4.30	4.52
FHLMC 6.5% (Gold)	2.79	3.95	4.89
FNMA 6.5%	2.79	3.75	4.58
FNMA ARM	3.15	4.26	4.67
Corporate Bonds			
Financial (10-year) A	7.85	7.56	6.06
Industrial (25/30-year) A	6.27	6.26	5.93
Utility (25/30-year) A	6.20	6.07	6.14
Utility (25/30-year) Baa/BBB	7.63	6.72	6.28
Foreign Bonds (10-Year)			
Canada	2.90	2.93	3.56
Germany	3.21	3.20	4.01
Japan	1.46	1.26	1.35
United Kingdom	3.35	3.29	4.51
Preferred Stocks			
Utility A	6.35	6.11	6.06
Financial A	7.80	7.28	6.60
Financial Adjustable A	5.48	5.48	5.48
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.95	5.24	4.90
25-Bond Index (Revs)	5.75	6.00	5.18
General Obligation Bonds (GOs)			
1-year Aaa	0.47	0.85	1.55
1-year A	1.20	0.95	1.70
5-year Aaa	2.03	2.48	2.94
5-year A	3.45	2.77	3.05
10-year Aaa	3.20	3.53	3.70
10-year A	4.75	4.03	3.90
25/30-year Aaa	4.77	5.04	4.78
25/30-year A	6.25	6.04	4.98
Revenue Bonds (Revs) (25/30-Year)			
Education AA	6.30	6.10	5.05
Electric AA	6.40	6.25	5.05
Housing AA	6.70	6.55	5.35
Hospital AA	6.65	6.50	5.30
Toll Road Aaa	6.45	6.25	5.10

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	3/25/09	3/11/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	771276	621568	149708	730382	566553	294869
Borrowed Reserves	604849	630177	-25328	591508	599533	385679
Net Free/Borrowed Reserves	166427	-8609	175036	138874	-32980	-90810

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

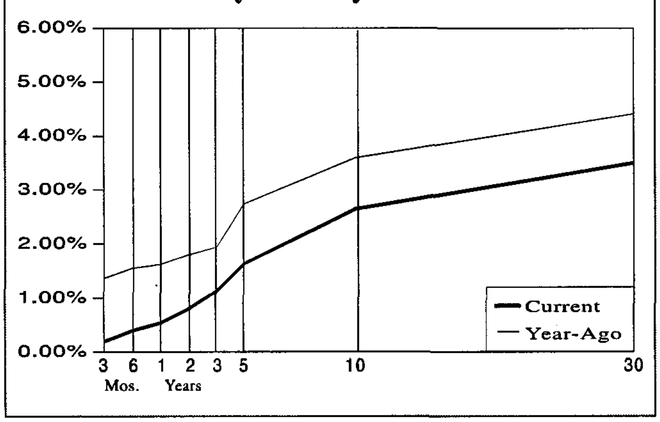
	Recent Levels			Growth Rates Over the Last...		
	3/23/09	3/16/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1551.1	1564.0	-12.9	-11.2%	10.8%	13.3%
M2 (M1+savings+small time deposits)	8372.3	8375.2	-2.9	10.1%	12.8%	9.9%

Selected Yields

	Recent (4/01/09)	3 Months Ago (12/30/08)	Year Ago (4/02/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.50
Federal Funds	0.00-0.25	0.00-0.25	2.25
Prime Rate	3.25	3.25	5.25
30-day CP (A1/P1)	0.44	0.06	2.67
3-month LIBOR	1.18	1.44	2.70
Bank CDs			
6-month	0.83	1.16	1.78
1-year	1.04	1.43	1.76
5-year	2.06	2.51	2.87
U.S. Treasury Securities			
3-month	0.20	0.09	1.37
6-month	0.39	0.24	1.55
1-year	0.54	0.31	1.62
5-year	1.64	1.44	2.74
10-year	2.65	2.05	3.60
10-year (inflation-protected)	1.32	2.33	1.12
30-year	3.50	2.56	4.41
30-year Zero	3.52	2.42	4.48

	Recent (4/01/09)	3 Months Ago (12/30/08)	Year Ago (4/02/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.53	4.11	4.81
FHLMC 6.5% (Gold)	3.12	4.03	5.05
FNMA 6.5%	3.04	3.89	4.79
FNMA ARM	3.15	4.22	4.67
Corporate Bonds			
Financial (10-year) A	7.49	7.08	6.30
Industrial (25/30-year) A	6.17	5.90	6.07
Utility (25/30-year) A	5.99	5.85	6.16
Utility (25/30-year) Baa/BBB	7.41	6.58	6.25
Foreign Bonds (10-Year)			
Canada	2.78	2.66	3.63
Germany	2.99	2.95	3.99
Japan	1.35	1.17	1.37
United Kingdom	3.13	3.09	4.43
Preferred Stocks			
Utility A	6.74	6.00	6.16
Financial A	9.90	7.89	6.74
Financial Adjustable A	5.48	5.48	5.48
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	5.00	5.46	4.96
25-Bond Index (Revs)	5.78	6.22	5.24
General Obligation Bonds (GOs)			
1-year Aaa	0.50	0.85	1.60
1-year A	0.60	0.95	1.70
5-year Aaa	2.08	2.57	3.00
5-year A	2.33	2.87	3.10
10-year Aaa	3.20	3.70	3.79
10-year A	3.73	4.20	4.00
25/30-year Aaa	4.79	5.17	4.91
25/30-year A	5.83	6.15	5.11
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.80	6.15	5.20
Electric AA	5.85	6.20	5.25
Housing AA	6.15	6.50	5.35
Hospital AA	6.20	6.55	5.40
Toll Road Aaa	5.90	6.25	5.25

Treasury Security Yield Curve



Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels 3/25/09	3/11/09	Change	Average Levels Over the Last... 12 Wks.	26 Wks.	52 Wks.
Excess Reserves	771194	621518	149676	730364	566544	294864
Borrowed Reserves	604849	630177	-25328	591508	599533	385679
Net Free/Borrowed Reserves	166345	-8659	175004	138856	-32990	-90815

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

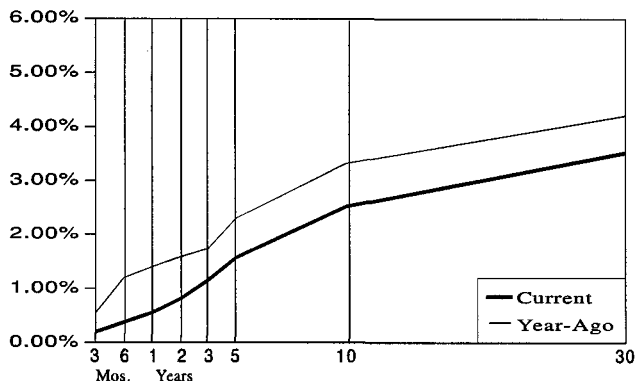
	Recent Levels 3/16/09	3/9/09	Change	Growth Rates Over the Last... 3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1565.6	1577.1	-11.5	-8.4%	19.8%	14.4%
M2 (M1+savings+small time deposits)	8376.2	8342.9	33.3	12.1%	18.2%	10.2%

Selected Yields

	Recent (3/25/09)	3 Months Ago (12/23/08)	Year Ago (3/26/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.50
Federal Funds	0.00-0.25	0.00-0.25	2.25
Prime Rate	3.25	3.25	5.25
30-day CP (A1/P1)	0.51	0.10	2.83
3-month LIBOR	1.23	1.47	2.67
Bank CDs			
6-month	0.83	1.17	1.84
1-year	1.04	1.56	1.84
5-year	2.06	2.72	2.87
U.S. Treasury Securities			
3-month	0.18	0.01	1.27
6-month	0.40	0.23	1.46
1-year	0.58	0.35	1.64
5-year	1.81	1.50	2.49
10-year	2.78	2.16	3.46
10-year (inflation-protected)	1.38	2.36	1.10
30-year	3.74	2.63	4.31
30-year Zero	3.77	2.67	4.45

	Recent (3/25/09)	3 Months Ago (12/23/08)	Year Ago (3/26/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.48	4.43	4.35
FHLMC 6.5% (Gold)	2.99	4.38	4.99
FNMA 6.5%	3.00	4.16	4.74
FNMA ARM	3.60	4.23	5.08
Corporate Bonds			
Financial (10-year) A	7.51	7.08	6.06
Industrial (25/30-year) A	6.48	6.02	6.11
Utility (25/30-year) A	6.28	5.90	6.03
Utility (25/30-year) Baa/BBB	7.71	7.07	6.24
Foreign Bonds (10-Year)			
Canada	2.96	2.80	3.47
Germany	3.15	2.95	3.88
Japan	1.29	1.22	1.28
United Kingdom	3.28	3.12	4.44
Preferred Stocks			
Utility A	6.11	6.25	6.02
Financial A	9.42	11.45	6.75
Financial Adjustable A	5.47	5.47	5.47
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.98	5.46	4.88
25-Bond Index (Revs)	5.81	6.22	5.17
General Obligation Bonds (GOs)			
1-year Aaa	0.50	0.85	1.70
1-year A	0.60	0.95	1.85
5-year Aaa	2.15	2.57	2.85
5-year A	2.45	2.87	2.95
10-year Aaa	3.24	3.70	3.74
10-year A	3.74	4.20	3.94
25/30-year Aaa	4.85	5.17	4.95
25/30-year A	5.85	6.15	5.15
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.90	6.15	5.20
Electric AA	6.00	6.20	5.20
Housing AA	6.30	6.50	5.50
Hospital AA	6.25	6.55	5.45
Toll Road Aaa	6.05	6.25	5.20

Treasury Security Yield Curve



Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	3/11/09	**2/25/09**	**Change**	**12 Wks.**	**26 Wks.**	**52 Wks.**
Excess Reserves	621518	673434	-51916	730828	511620	266354
Borrowed Reserves	630177	588910	41267	601461	568436	365508
Net Free/Borrowed Reserves	-8659	84524	-93183	129367	-56816	-99154

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	3/9/09	**3/2/09**	**Change**	**3 Mos.**	**6 Mos.**	**12 Mos.**
M1 (Currency+demand deposits)	1577.1	1561.3	15.8	-0.2%	24.5%	14.5%
M2 (M1+savings+small time deposits)	8343.1	8303.3	39.8	12.8%	17.8%	10.1%

UNS GAS, INC.

DOCKET NO. G-04204A-08-0571

TABLE OF CONTENTS TO SCHEDULES WAR

SCHEDULE #	
WAR - 1	COST OF CAPITAL SUMMARY
WAR - 2	DCF COST OF EQUITY CAPITAL
WAR - 3	DIVIDEND YIELD CALCULATION
WAR - 4	DIVIDEND GROWTH RATE CALCULATION
WAR - 5	DIVIDEND GROWTH COMPONENTS
WAR - 6	GROWTH RATE COMPARISON
WAR - 7	CAPM COST OF EQUITY CAPITAL
WAR - 8	ECONOMIC INDICATORS - 1990 TO PRESENT
WAR - 9	CAPITAL STRUCTURES OF SAMPLE COMPANIES

UNS GAS, INC.
TEST YEAR ENDED JUNE 30, 2008
COST OF CAPITAL SUMMARY

ORIGINAL COST WEIGHTED AVERAGE COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) CAPITALIZATION PER COMPANY	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED CAPITALIZATION	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
1	SHORT-TERM DEBT	$ -	$ -	$ -	0.00%	0.00%	0.00%
2	LONG-TERM DEBT	99,265	-	99,265	50.01%	6.49%	3.25%
3	COMMON EQUITY	99,242	-	99,242	49.99%	8.61%	4.30%
4	TOTAL CAPITALIZATION	$ 198,507	$ -	$ 198,507	100.00%		
5	**ORIGINAL COST WEIGHTED AVERAGE COST OF CAPITAL**						**7.55%**

WEIGHTED COST OF DEBT

LINE NO.	(A) DESCRIPTION	(B) BALANCE	(C) ANNUAL INTEREST	(D) INTEREST RATE	(E) BALANCE RATIOS	(F) WEIGHTED COST OF DEBT
1	UNS GAS SERIES A BONDS	$ 50,000	$ 3,115	6.23%	50.00%	3.115%
2	UNS GAS SERIES B BONDS	50,000	3,115	6.23%	50.00%	3.115%
3	TOTALS	$ 100,000	$ 6,230		100.00%	6.23%
4	UNAMORTIZED DEBT DISCOUNT, PREMIUM AND EXPENSE ON REAQUIRED DEBT	$ (735)				
5	AMORTIZATION OF DEBT DISCOUNT AND EXPENSE AND LOSS ON REAQUIRED DEBT		$ 170			
6	CREDIT FACILITY COMMITMENT FEES		43			
7	TOTAL COST OF LONG-TERM DEBT - NET	$ 99,265	$ 6,443	6.49%	100.00%	
8	**WEIGHTED COST OF DEBT**					**6.49%**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-2, PAGE 2
COLUMN (B): COMPANY SCHEDULE D-2, PAGE 2
COLUMN (C): COMPANY SCHEDULE D-2, PAGE 2
COLUMN (D): COLUMN (C) ÷ COLUMN (D)
COLUMN (E): COLUMN (A) LINES 1 AND 2 ÷ LINE 3
COLUMN (F): COLUMN (D) x COLUMN (E)

COST OF COMMON EQUITY CALCULATION

LINE NO.			
1	**DCF METHODOLOGY**		
2	DCF - SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	11.40%	SCHEDULE WAR-2, COLUMN (C), LINE 11
3	**CAPM METHODOLOGY**		
4	CAPM - GEOMETRIC MEAN ESTIMATE	5.26%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 11
5	CAPM - ARITHMETIC MEAN ESTIMATE	6.39%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 11
6	AVERAGE OF CAPM ESTIMATES	5.82%	(LINE 4 + LINE 5) ÷ 2
7	**AVERAGE OF DCF AND CAPM ESTIMATES**	**8.61%**	(LINE 2 + LINE 6) ÷ 2

INFLATION ADJUSTMENT TO RUCO'S RECOMMENDED ORIGINAL COST OF EQUITY CAPITAL

LINE NO.	(A) YEAR	(B) VALUE TIPS	(C) VALUE BONDS	(D) DIFFERENCE
1	2001	3.31%	5.02%	1.71%
2	2002	2.85%	4.61%	1.76%
3	2003	1.81%	4.01%	2.20%
4	2004	1.37%	4.27%	2.90%
5	2005	1.53%	4.29%	2.76%
6	2006	2.25%	4.80%	2.55%
7	2007	2.10%	4.63%	2.53%
8	2008	0.13%	3.79%	3.66%
9	AVERAGE	1.92%	4.43%	2.51%
10	**INFLATION ADJUSTMENT TO RUCO'S RECOMMENDED ORIGINAL COST OF EQUITY CAPITAL**			**2.50%**

REFERENCES

COLUMNS (A), (B) AND (C): FEDERAL RESERVE BANK OF ST. LOUIS WEBSITE
COLUMN (D): COLUMN (C) - COLUMN (D)

UNS GAS, INC.
TEST YEAR ENDED JUNE 30, 2008
DCF COST OF EQUITY CAPITAL

DOCKET NO. G-04204A-08-0571
SCHEDULE WAR - 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) DIVIDEND YIELD	+	(B) GROWTH RATE (g)	=	(C) DCF COST OF EQUITY CAPITAL
1	AGL	AGL RESOURCES, INC.	6.07%	+	5.58%	=	11.64%
2	ATO	ATMOS ENERGY CORPORATION	5.55%	+	11.03%	=	16.58%
3	LG	LACLEDE GROUP, INC.	4.41%	+	5.28%	=	9.69%
4	NJR	NEW JERSEY RESOURCES CORP.	3.81%	+	5.71%	=	9.52%
5	GAS	NICOR, INC.	5.72%	+	5.02%	=	10.74%
6	NWN	NORTHWEST NATURAL GAS CO.	3.78%	+	4.94%	=	8.72%
7	PNY	PIEDMONT NATURAL GAS COMPANY	4.24%	+	5.50%	=	9.75%
8	SJI	SOUTH JERSEY INDUSTIES, INC.	6.51%	+	7.90%	=	14.42%
9	SWX	SOUTHWEST GAS CORP.	4.71%	+	9.03%	=	13.74%
10	WGL	WGL HOLDINGS, INC.	4.67%	+	4.52%	=	9.19%
11	**NATURAL GAS LDC AVERAGE**						**11.40%**

REFERENCES:
COLUMN (A): SCHEDULE WAR - 3, COLUMN C
COLUMN (B): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

LINE NO.	STOCK SYMBOL	COMPANY	(A) ESTIMATED DIVIDEND (PER SHARE)	÷	(B) AVERAGE STOCK PRICE (PER SHARE)	=	(C) DIVIDEND YIELD
1	AGL	AGL RESOURCES, INC.	$1.72	÷	$28.35	=	6.07%
2	ATO	ATMOS ENERGY CORPORATION	1.32	÷	23.79	=	5.55%
3	LG	LACLEDE GROUP, INC.	1.54	÷	34.89	=	4.41%
4	NJR	NEW JERSEY RESOURCES CORP.	1.24	÷	32.51	=	3.81%
5	GAS	NICOR, INC.	1.86	÷	32.52	=	5.72%
6	NWN	NORTHWEST NATURAL GAS CO.	1.58	÷	41.80	=	3.78%
7	PNY	PIEDMONT NATURAL GAS COMPANY	1.04	÷	24.50	=	4.24%
8	SJI	SOUTH JERSEY INDUSTIES, INC.	2.27	÷	34.87	=	6.51%
9	SWX	SOUTHWEST GAS CORP.	0.95	÷	20.23	=	4.71%
10	WGL	WGL HOLDINGS, INC.	1.44	÷	30.85	=	4.67%
11	**NATURAL GAS LDC AVERAGE**						**4.95%**

REFERENCES:
COLUMN (A): ESTIMATED 12 MONTH DIVIDEND REPORTED IN VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/13/2009.
COLUMN (B): EIGHT WEEK AVERAGE OF CLOSING PRICES FROM 03/30/2009 TO 05/22/2009 STOCK QUOTES OBTAINED THROUGH BIG CHARTS WEB SITE - HISTORICAL QUOTES (www.bigcharts.com).
COLUMN (C): COLUMN (A) ÷ COLUMN (B)

UNS GAS, INC.
TEST YEAR ENDED JUNE 30, 2008
DIVIDEND GROWTH RATE CALCULATION

LINE NO.	STOCK SYMBOL	COMPANY	(A) INTERNAL GROWTH (br)	+	(B) EXTERNAL GROWTH (sv)	=	(C) DIVIDEND GROWTH (g)
1	AGL	AGL RESOURCES, INC.	5.30%	+	0.28%	=	5.58%
2	ATO	ATMOS ENERGY CORPORATION	4.05%	+	6.98%	=	11.03%
3	LG	LACLEDE GROUP, INC.	4.50%	+	0.78%	=	5.28%
4	NJR	NEW JERSEY RESOURCES CORP.	5.25%	+	0.46%	=	5.71%
5	GAS	NICOR, INC.	5.00%	+	0.02%	=	5.02%
6	NWN	NORTHWEST NATURAL GAS CO.	4.60%	+	0.34%	=	4.94%
7	PNY	PIEDMONT NATURAL GAS COMPANY	5.50%	+	0.00%	=	5.50%
8	SJI	SOUTH JERSEY INDUSTIES, INC.	7.00%	+	0.90%	=	7.90%
9	SWX	SOUTHWEST GAS CORP.	4.25%	+	4.78%	=	9.03%
10	WGL	WGL HOLDINGS, INC.	4.50%	+	0.02%	=	4.52%
11	**NATURAL GAS LDC AVERAGE**						**6.45%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

LINE NO.	STOCK SYMBOL	COMPANY	(A) SHARE GROWTH	x	(B) { [((M ÷ B) + 1) ÷ 2] - 1 }	=	(C) EXTERNAL GROWTH (sv)
1	AGL	AGL RESOURCES, INC.	1.75%	x	{ [((1.32) + 1) ÷ 2] - 1 }	=	0.28%
2	ATO	ATMOS ENERGY CORPORATION	3.50%	x	{ [((0.99) + 1) ÷ 2] + 1 }	=	6.98%
3	LG	LACLEDE GROUP, INC.	3.25%	x	{ [((1.48) + 1) ÷ 2] - 1 }	=	0.78%
4	NJR	NEW JERSEY RESOURCES CORP.	1.25%	x	{ [((1.73) + 1) ÷ 2] - 1 }	=	0.46%
5	GAS	NICOR, INC.	0.10%	x	{ [((1.46) + 1) ÷ 2] - 1 }	=	0.02%
6	NWN	NORTHWEST NATURAL GAS CO.	1.00%	x	{ [((1.68) + 1) ÷ 2] - 1 }	=	0.34%
7	PNY	PIEDMONT NATURAL GAS COMPANY	0.01%	x	{ [((1.94) + 1) ÷ 2] - 1 }	=	0.00%
8	SJI	SOUTH JERSEY INDUSTIES, INC.	2.00%	x	{ [((1.90) + 1) ÷ 2] - 1 }	=	0.90%
9	SWX	SOUTHWEST GAS CORP.	2.50%	x	{ [((0.83) + 1) ÷ 2] + 1 }	=	4.78%
10	WGL	WGL HOLDINGS, INC.	0.10%	x	{ [((1.40) + 1) ÷ 2] - 1 }	=	0.02%
11	**NATURAL GAS LDC AVERAGE**						**1.46%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY RATINGS & REPORTS DATED 03/13/2009
COLUMN (C): COLUMN (A) x COLUMN (B)

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	AGL	AGL RESOURCES, INC.	2004	0.4956		11.00%		5.45%	18.06	76.70	
2			2005	0.4758		12.90%		6.14%	19.29	77.70	
3			2006	0.4559		13.20%		6.02%	20.71	77.70	
4			2007	0.3971		12.70%		5.04%	21.74	76.40	
5			2008	0.3801		12.60%		4.79%	21.48	76.90	
6			GROWTH 2002 - 2008					5.49%	11.50%		0.07%
7			2009	0.3630		12.50%		4.54%		78.00	1.43%
8			2010	0.3825		13.00%		4.97%		79.00	1.36%
9			2012-14	0.4125		14.50%		5.98%	0.50%	85.00	2.02%
10											
11	ATO	ATMOS ENERGY CORPORATION	2004	0.2278		7.60%		1.73%	18.05	62.80	
12			2005	0.2791		8.50%		2.37%	19.90	80.54	
13			2006	0.3700		9.80%		3.63%	20.16	81.74	
14			2007	0.3402		8.70%		2.96%	22.01	89.33	
15			2008	0.3500		8.80%		3.08%	22.60	90.81	
16			GROWTH 2002 - 2008					2.75%	7.50%		9.66%
17			2009	0.3714		9.00%		3.34%		92.00	1.31%
18			2010	0.3767		8.50%		3.20%		93.00	1.20%
19			2012-14	0.4400		9.50%		4.18%	4.00%	110.00	3.91%
20											
21	LG	LACLEDE GROUP, INC.	2004	0.2582		10.10%		2.61%	16.96	20.98	
22			2005	0.2789		10.90%		3.04%	17.31	21.17	
23			2006	0.4093		12.50%		5.12%	18.85	21.36	
24			2007	0.3723		11.60%		4.32%	19.79	21.65	
25			2008	0.4356		11.80%		5.14%	22.12	21.99	
26			GROWTH 2002 - 2008					4.04%	5.50%		1.18%
27			2009	0.4632		12.50%		5.79%		22.50	2.32%
28			2010	0.3962		10.50%		4.16%		23.00	2.27%
29			2012-14	0.4333		11.00%		4.77%	5.50%	26.00	3.41%
30											
31	NJR	NEW JERSEY RESOURCES CORP.	2004	0.4882		15.30%		7.47%	11.25	41.61	
32			2005	0.4859		17.00%		8.26%	10.60	41.32	
33			2006	0.4866		12.60%		6.13%	15.00	41.44	
34			2007	0.3484		10.10%		3.52%	15.50	41.61	
35			2008	0.5889		15.70%		9.25%	17.28	42.06	
36			GROWTH 2002 - 2008					6.93%	11.50%		0.27%
37			2009	0.5040		13.50%		6.80%		42.50	1.05%
38			2010	0.5259		13.00%		6.84%		43.00	1.11%
39			2012-14	0.5088		11.00%		5.60%	8.50%	45.00	1.36%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY RATINGS & REPORTS DATED 03/13/2009
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 26 & 36, SIMPLE AVERAGE GROWTH, 2004 - 2008

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	GAS	NICOR, INC.	2004	0.1622		13.10%		2.12%	16.99	44.10	
2			2005	0.1806		12.50%		2.26%	18.36	44.18	
3			2006	0.3519		14.70%		5.17%	19.43	44.90	
4			2007	0.3779		14.30%		5.40%	20.58	45.90	
5			2008	0.2928		12.30%		3.60%	21.55	45.13	
6			GROWTH 2002 - 2008					3.71%	4.00%		0.58%
7			2009	0.2560		11.00%		2.82%		45.00	-0.29%
8			2010	0.3586		12.50%		4.48%		45.00	-0.14%
9			2012-14	0.4364		12.00%		5.24%	4.50%	45.00	-0.06%
10											
11	NWN	NORTHWEST NATURAL GAS CO.	2004	0.3011		8.90%		2.68%	20.64	27.55	
12			2005	0.3744		9.90%		3.71%	21.28	27.58	
13			2006	0.4085		10.90%		4.45%	22.01	27.24	
14			2007	0.4783		12.50%		5.98%	22.52	26.41	
15			2008	0.4109		11.20%		4.60%	23.70	26.50	
16			GROWTH 2002 - 2008					4.28%	3.50%		-0.97%
17			2009	0.4255		11.00%		4.68%		26.50	0.00%
18			2010	0.4175		11.00%		4.59%		26.50	0.00%
19			2012-14	0.4203		11.00%		4.62%	3.50%	28.00	1.11%
20											
21	PNY	PIEDMONT NATURAL GAS COMPANY	2004	0.3307		11.10%		3.67%	11.15	76.67	
22			2005	0.3106		11.50%		3.57%	11.53	76.70	
23			2006	0.2578		11.00%		2.84%	11.83	74.61	
24			2007	0.2929		11.90%		3.49%	11.99	73.23	
25			2008	0.3087		12.40%		3.83%	12.11	73.26	
26			GROWTH 2002 - 2008					3.48%	6.00%		-1.13%
27			2009	0.3438		12.50%		4.30%		73.50	0.33%
28			2010	0.3889		13.50%		5.25%		73.50	0.16%
29			2012-14	0.4186		13.50%		5.65%	5.00%	73.00	-0.07%
30											
31	SJI	SOUTH JERSEY INDUSTIES, INC.	2004	0.4810		12.50%		6.01%	12.41	27.76	
32			2005	0.4971		12.40%		6.16%	13.50	28.98	
33			2006	0.6260		16.30%		10.20%	15.11	29.33	
34			2007	0.5167		12.80%		6.61%	16.25	29.61	
35			2008	0.5110		13.20%		6.75%	17.33	29.73	
36			GROWTH 2002 - 2008					7.15%	12.50%		1.73%
37			2009	0.5102		13.50%		6.89%		30.50	2.59%
38			2010	0.5170		13.50%		6.98%		31.00	2.11%
39			2012-14	0.5161		14.50%		7.48%	4.50%	33.00	2.11%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY RATINGS & REPORTS DATED 03/13/2009
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 26 & 36, SIMPLE AVERAGE GROWTH, 2004 - 2008

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

UNS GAS, INC.
TEST YEAR ENDED JUNE 30, 2008
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	SWX	SOUTHWEST GAS CORP.	2004	0.5060		8.30%		4.20%	19.18	36.79	
2			2005	0.3440		6.40%		2.20%	19.10	39.33	
3			2006	0.5859		8.90%		5.21%	21.58	41.77	
4			2007	0.5590		8.50%		4.75%	22.98	42.81	
5			2008	0.3525		5.90%		2.08%	23.48	44.19	
6			GROWTH 2002 - 2008					3.69%	4.00%		4.69%
7			2009	0.3667		6.00%		2.20%		45.00	1.83%
8			2010	0.4595		7.50%		3.45%		46.00	2.03%
9			2012-14	0.5000		9.00%		4.50%	2.50%	50.00	2.50%
10											
11	WGL	WGL HOLDINGS, INC.	2004	0.3434		11.70%		4.02%	16.95	48.67	
12			2005	0.3803		11.70%		4.45%	17.80	48.65	
13			2006	0.3041		10.30%		3.13%	18.86	48.89	
14			2007	0.3476		10.40%		3.62%	19.83	49.45	
15			2008	0.4221		11.60%		4.90%	20.99	49.92	
16			GROWTH 2002 - 2008					4.02%	4.50%		0.64%
17			2009	0.4200		12.00%		5.04%		50.00	0.16%
18			2010	0.4118		11.50%		4.74%		50.00	0.08%
19			2012-14	0.4182		11.00%		4.60%	5.00%	50.00	0.03%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY RATINGS & REPORTS DATED 03/13/2009
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6 & 16, SIMPLE AVERAGE GROWTH, 2004 - 2008
COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6 & 16, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

UNS GAS, INC.
TEST YEAR ENDED JUNE 30, 2008
GROWTH RATE COMPARISON

DOCKET NO. G-04204A-08-0571
SCHEDULE WAR - 6

LINE NO.	STOCK SYMBOL	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	(C) DPS	(C) BVPS	(D) VALUE LINE HISTORIC EPS	(D) DPS	(D) BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	(F) DPS	(F) BVPS
1	AGL	5.58%	5.30%	3.00%	2.50%	0.50%	11.50%	6.50%	11.50%	5.83%	4.41%	9.94%	4.43%
2	ATO	11.03%	5.80%	4.00%	1.50%	4.00%	5.00%	1.50%	7.50%	4.19%	9.74%	2.50%	6.87%
3	LG	5.28%	6.50%	3.50%	2.50%	5.50%	9.50%	1.50%	5.50%	4.93%	4.33%	0.00%	6.12%
4	NJR	5.71%	8.00%	5.50%	5.50%	8.50%	7.50%	5.00%	11.50%	7.36%	4.07%	4.92%	2.09%
5	GAS	5.02%	5.90%	2.50%	-	4.50%	1.00%	0.50%	4.00%	3.07%	-4.34%	2.35%	5.19%
6	NWN	4.94%	6.80%	7.00%	5.50%	3.50%	6.50%	2.00%	3.50%	4.97%	5.99%	4.15%	5.95%
7	PNY	5.50%	6.50%	7.50%	3.50%	5.00%	6.50%	4.50%	6.00%	5.64%	0.00%	0.00%	0.00%
8	SJI	7.90%	8.40%	5.50%	7.00%	4.50%	12.50%	4.50%	12.50%	7.84%	0.00%	0.00%	0.00%
9	SWX	9.03%	6.00%	4.50%	5.00%	2.50%	8.00%	0.50%	4.00%	4.36%	0.00%	0.00%	0.00%
10	WGL	4.52%	6.70%	4.00%	2.50%	5.00%	4.00%	1.50%	4.50%	4.03%	0.00%	0.00%	0.00%
11				4.70%	3.94%	4.35%	7.20%	2.80%	7.05%		2.42%	2.39%	3.06%
12	AVERAGES	6.45%	6.59%		4.33%			5.68%		5.22%		2.62%	

REFERENCES:
COLUMN (A): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (B): ZACKS INVESTMENT RESEARCH (www.zacks.com)
COLUMN (C): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/13/2009
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/13/2006
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1 THRU 10
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/13/2009

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x (	r_m	-	r_f)]	=	(B) EXPECTED RETURN
1	AGL	k	=	1.87%	+ [	0.75	x (	10.40%	-	5.30%)]	=	5.69%
2	ATO	k	=	1.87%	+ [	0.60	x (	10.40%	-	5.30%)]	=	4.93%
3	LG	k	=	1.87%	+ [	0.65	x (	10.40%	-	5.30%)]	=	5.18%
4	NJR	k	=	1.87%	+ [	0.65	x (	10.40%	-	5.30%)]	=	5.18%
5	GAS	k	=	1.87%	+ [	0.75	x (	10.40%	-	5.30%)]	=	5.69%
6	NWN	k	=	1.87%	+ [	0.60	x (	10.40%	-	5.30%)]	=	4.93%
7	PNY	k	=	1.87%	+ [	0.65	x (	10.40%	-	5.30%)]	=	5.18%
8	SJI	k	=	1.87%	+ [	0.65	x (	10.40%	-	5.30%)]	=	5.18%
9	SWX	k	=	1.87%	+ [	0.70	x (	10.40%	-	5.30%)]	=	5.44%
10	WGL	k	=	1.87%	+ [	0.65	x (	10.40%	-	5.30%)]	=	5.18%
11	AVERAGE					0.67						5.26%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [\,ß\,(r_m - r_f)\,]$$

WHERE:
k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)
r_f = PROXY FOR THE RISK FREE RATE ON INTERMEDIATE TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 5-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN *VALUE LINE INVESTMENT SURVEY*'S "SELECTION & OPINIONS" PUBLICATION FROM 04/03/2009 THROUGH 05/22/2009 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE RISK PREMIUM (RM - RF) USED THE GEOMETRIC MEAN FOR S&P 500 TOTAL RETURNS OVER THE 1926 - 2007 PERIOD MINUS TOTAL RETURNS ON INTERMEDIATE TREASURIES OVER THE SAME PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2008 YEARBOOK.

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x (	r_m	-	r_f)]	=	(B) EXPECTED RETURN
1	AGL	k	=	1.87%	+ [	0.75	x (	12.30%	-	5.50%)]	=	6.97%
2	ATO	k	=	1.87%	+ [	0.60	x (	12.30%	-	5.50%)]	=	5.95%
3	LG	k	=	1.87%	+ [	0.65	x (	12.30%	-	5.50%)]	=	6.29%
4	NJR	k	=	1.87%	+ [	0.65	x (	12.30%	-	5.50%)]	=	6.29%
5	GAS	k	=	1.87%	+ [	0.75	x (	12.30%	-	5.50%)]	=	6.97%
6	NWN	k	=	1.87%	+ [	0.60	x (	12.30%	-	5.50%)]	=	5.95%
7	PNY	k	=	1.87%	+ [	0.65	x (	12.30%	-	5.50%)]	=	6.29%
8	SJI	k	=	1.87%	+ [	0.65	x (	12.30%	-	5.50%)]	=	6.29%
9	SWX	k	=	1.87%	+ [	0.70	x (	12.30%	-	5.50%)]	=	6.63%
10	WGL	k	=	1.87%	+ [	0.65	x (	12.30%	-	5.50%)]	=	6.29%
11	**AVERAGE**					**0.67**						**6.39%**

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$k = r_f + [ß (r_m - r_f)]$

WHERE:
k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)
r_f = PROXY FOR THE RISK FREE RATE ON INTERMEDIATE TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 5-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 04/03/2009 THROUGH 05/22/2009 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE RISK PREMIUM (RM - RF) USED THE ARITHMETIC MEAN FOR S&P 500 TOTAL RETURNS OVER THE 1926 - 2007 PERIOD MINUS TOTAL RETURNS ON INTERMEDIATE TREASURIES OVER THE SAME PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2008 YEARBOOK

UNS GAS, INC.
TEST YEAR ENDED JUNE 30, 2008
ECONOMIC INDICATORS - 1990 TO PRESENT

DOCKET NO. G-04204A-08-0571
SCHEDULE WAR - 8

LINE NO.	YEAR	(A) CHANGE IN CPI	(B) CHANGE IN GDP (1996 $)	(C) PRIME RATE	(D) FED. DISC. RATE	(E) FED. FUNDS RATE	(F) 91-DAY T-BILLS	(G) 30-YR T-BONDS	(H) A-RATED UTIL. BOND YIELD	(I) Baa-RATED UTIL. BOND YIELD
1	1990	5.39%	1.90%	10.01%	6.98%	8.10%	7.50%	7.49%	9.86%	10.06%
2	1991	4.25%	-0.20%	8.46%	5.45%	5.69%	5.38%	5.38%	9.36%	9.55%
3	1992	3.03%	3.30%	6.25%	3.25%	3.52%	3.43%	3.43%	8.69%	8.86%
4	1993	2.96%	2.70%	6.00%	3.00%	3.02%	3.00%	3.00%	7.59%	7.91%
5	1994	2.61%	4.00%	7.14%	3.60%	4.21%	4.25%	4.25%	8.31%	8.63%
6	1995	2.81%	2.50%	8.83%	5.21%	5.83%	5.49%	5.49%	7.89%	8.29%
7	1996	2.93%	3.70%	8.27%	5.02%	5.30%	5.01%	5.01%	7.75%	8.17%
8	1997	2.34%	4.50%	8.44%	5.00%	5.46%	5.06%	5.06%	7.60%	8.12%
9	1998	1.55%	4.20%	8.35%	4.92%	5.35%	4.78%	4.78%	7.04%	7.27%
10	1999	2.19%	4.50%	7.99%	4.62%	4.97%	4.64%	4.64%	7.62%	7.88%
11	2000	3.38%	3.70%	9.23%	5.73%	6.24%	5.82%	5.82%	8.24%	8.36%
12	2001	2.83%	0.80%	6.92%	3.41%	3.88%	3.40%	5.95%	7.59%	8.02%
13	2002	1.59%	1.60%	4.67%	1.17%	1.67%	1.61%	5.38%	7.41%	7.98%
14	2003	2.27%	2.50%	4.12%	2.03%	1.13%	1.01%	4.92%	6.18%	6.64%
15	2004	2.68%	3.60%	4.34%	2.34%	1.35%	1.37%	5.03%	5.77%	6.20%
16	2005	3.39%	2.90%	6.16%	4.19%	3.22%	3.15%	4.57%	5.38%	5.78%
17	2006	3.24%	2.80%	7.97%	5.96%	4.97%	4.73%	4.91%	5.94%	6.30%
18	2007	2.85%	2.00%	8.05%	5.86%	5.02%	4.36%	4.84%	6.07%	6.24%
19	2008	3.58%	1.30%	5.09%	2.39%	1.92%	1.37%	4.28%	6.34%	6.64%
20	CURRENT	0.10%	-6.10%	3.25%	0.50%	0.00% - 0.25%	0.17%	4.10%	6.01%	7.57%

REFERENCES:
COLUMN (A): 1990 - CURRENT, U.S. DEPARTMENT OF LABOR, BUREAU OF LABOR STATISTICS WEB SITE
COLUMN (B): 1990 - CURRENT, U.S. DEPARTMENT OF COMMERCE, BUREAU OF ECONOMIC ANALYSIS WEB SITE
COLUMN (C) THROUGH (G): 1990 - 2003, FEDERAL RESERVE BANK OF ST. LOUIS WEB SITE
COLUMN (C) THROUGH (D): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 05/22/2009
COLUMN (F) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 05/22/2009
COLUMN (H) THROUGH (I): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL

UNS GAS, INC.
TEST YEAR ENDED JUNE 30, 2008
CAPITAL STRUCTURES OF SAMPLE COMPANIES

DOCKET NO. G-04204A-08-0571
SCHEDULE WAR - 9

LINE NO.		AGL	PCT.	ATO	PCT.	LG	PCT.	NJR	PCT.	GAS	PCT.
1	DEBT	$ 1,675.0	50.3%	$ 2,119.8	50.8%	$ 389.2	44.4%	$ 455.1	38.5%	$ 448.0	31.5%
3	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.5	0.1%	0.0	0.0%	0.6	0.0%
5	COMMON EQUITY	1,652.0	49.7%	2,052.5	49.2%	486.5	55.5%	727.0	61.5%	973.1	68.4%
7	TOTALS	$ 3,327.0	100%	$ 4,172.3	100%	$ 876.2	100%	$ 1,182.1	100%	$ 1,421.7	100%

LINE NO.		NWN	PCT.	PNY	PCT.	SJI	PCT.	SWX	PCT.	WGL	PCT.
12	DEBT	$ 512.0	44.9%	$ 794.3	47.2%	$ 332.8	39.2%	$ 1,185.5	51.0%	$ 603.7	38.5%
14	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.0	0.0%	100.0	4.3%	28.2	1.8%
16	COMMON EQUITY	628.4	55.1%	887.2	52.8%	515.3	60.8%	1,037.8	44.7%	935.1	59.7%
18	TOTALS	$ 1,140.4	100%	$ 1,681.5	100%	$ 848.1	100%	$ 2,323.3	100%	$1,567.0	100%

LINE NO.		NATURAL GAS LDC AVERAGE	PCT.
24	DEBT	$ 851.5	45.9%
26	PREFERRED STOCK	12.9	0.7%
28	COMMON EQUITY	989.5	53.4%
30	TOTALS	$ 1,854.0	100%

REFERENCE:
MOST RECENT SEC 10-K FILINGS OR ANNUAL REPORTS

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)))))))	DOCKET NO. G-04204A-08-0571

REDACTED DIRECT

TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 8, 2009

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EXECUTIVE SUMMARY
UNS GAS, INC.
DOCKET NO. G-04204A-08-0571
TESTIMONY OF STAFF WITNESS RALPH C. SMITH

My testimony addresses the following issues, and responds to the testimony of UNS Gas, Inc. ("UNSG", "UNS Gas," or "Company") witnesses on these issues:

- The Company's proposed revenue requirement
- The determination of a Fair Value Rate of Return and its application to Fair Value Rate Base
- RUCO's recommended base revenue increase
- Adjusted Rate base
- Adjusted Test year revenues, expenses, and net operating income

My findings and recommendations for each of these areas are as follows:

The Company's Proposed Revenue Requirement
The Company's proposed revenue requirement of a base rate increase of $9.480 million, or 18.53 percent, is significantly overstated. In its filing, UNSG calculated the same revenue deficiency on its proposed original cost rate base (OCRB) and fair value rate base (FVRB).

UNSG overstated rate base and understated operating income. Additionally, the Company is requesting an excessive rate of return.

UNSG's request for a 9.54 percent overall return on OCRB could be viewed as effectively requesting a return on equity of 12.58 percent on OCRB, as shown on my Attachment RCS-2, Schedule D, page 1, and summarized below:

UNS Gas Proposed to Show Equivalent Requested ROE

Capital Source	Capitalization Percent	Cost Rate	Weighted Avg. Cost of Capital
Long-Term Debt	50.01%	6.49%	3.25%
Common Stock Equity	49.99%	**12.58%**	6.29%
Overall Cost of Capital	100.00%		9.54%

The testimony of RUCO witness William Rigsby addresses RUCO's recommended return on equity and weighted cost of capital to be applied to OCRB.

The Determination of a Fair Value Rate of Return (FVROR) and its Application to FVRB
The Commission's traditional calculation of return on fair value rate base calculation has been called into question by a recent Arizona Court of Appeals ruling involving Chaparral City Water Company. In that ruling, the Arizona Court of Appeals found that Staff's determination of operating income in that case had ignored fair value rate base, and that the Commission must use fair value rate base to set rates per the Arizona Constitution.

That Court of Appeals decision provided some guidance for calculating the return on fair value rate base. For example, at pages 13-14, paragraph 17, the Court of Appeals decision stated that: "... the Commission cannot ignore its constitutional obligation to base rates on a utility's fair value. The Commission cannot determine rates based on the original cost, or OCRB, and then engage in a superfluous mathematical exercise to identify the equivalent FVRB rate of return. Such a method is inconsistent with Arizona law." At page 13, the decision stated that: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology."

The Commission reopened Docket No. W-02113A-04-0616 to address such issues in a Chaparral City remand proceeding and, on July 28, 2008, issued Decision No. 70441. In Decision No. 70441, the Commission determined the rate of return on FVRB that was reasonable and appropriate for Chaparral City, noting that there are many methods the Commission can use to determine an appropriate FVROR, including adjusting the weighted average cost of capital ("WACC") to exclude the effect of inflation on the cost of equity, and that the FVROR adopted there fell within the range of recommendations in that proceeding and reflected the Commission's exercise of its expertise and discretion in the ratemaking process.

My direct testimony in the instant rate case describes RUCO's derivation of the fair value return on fair value rate base calculations in view of the Court of Appeals decision concerning Chaparral and the Commission's Decision No. 70441 in the Chaparral remand case, as described above. Attachment RCS-2, Schedule D, page 2, shows the derivation of four FVROR calculations that were considered by RUCO, including:

- Calculation 1 - Reduce Recommended OCRB-Based Return on Equity for Estimated Inflation
- Calculation 2 - Reduce Recommended OCRB-Based Overall Rate of Return for Estimated Inflation
- Calculation 3 - With Fair Value Rate Base Increment at Zero Cost
- Calculation 4 - With Fair Value Rate Base Increment at 1.25 Percent

My Attachment RCS-2, Schedule A, page 2, in columns A through D, summarizes the resulting revenue deficiencies that would be produced in the current UNSG rate case from each of those FVROR figures, and in Column E shows RUCO's recommended FVROR of 5.38 percent. RUCO's recommendation falls within the range of FVRORs developed using various calculation methods, and is near, but not at the low end of that range. I believe that this information and RUCO's recommended FVROR in the current UNSG rate case that was made after considering these alternatives appropriately fulfills the requirement of the Arizona Constitution that the Commission must base rates on a utility's fair value.

My Attachment RCS-2, Schedule A, page 1, Column D, shows the amount of base rate revenue increase on FVRB of $841,000.

Recommended Base Rate Revenue Increase

On original cost rate base (OCRB) my calculations show a jurisdictional revenue deficiency of $803,000 and $841,000 on FVRB, based on a FVROR of 5.38 percent. I recommend that UNSG be authorized a base rate increase of no more than $841,000 on adjusted FVRB. That is an average revenue increase of approximately 1.63 percent over adjusted test year revenue of $51.674 million.

Adjusted Rate Base

The following adjustments to UNSG's proposed original cost rate base should be made:

Summary of RUCO Adjustments to Rate Base

Adj. No.	Description		Increase (Decrease)	Note
B-1	Construction Work in Progress/Post Test Year Plant	$	(1,527,588)	
B-2	Customer Advances	$	(589,152)	
B-3	Prepayments	$	(95,671)	
B-4	Cash Working Capital	$	-	[a]
B-5	Customer Deposits	$	-	[a]
B-6	Accumulated Deferred Income Taxes	$	(196,256)	
	Total of RUCO Adjustments	$	(2,408,667)	
	UNS Proposed Rate Base (Original Cost)	$	182,293,106	
	RUCO Proposed Rate Base (Original Cost)	$	179,884,439	

[a] Schedule is a placeholder for a potential adjustment to be submitted in a later stage filing, such as surrebuttal

The following table summarizes UNS Gas' requested and RUCO's recommend OCRB, reconstruction cost new depreciated (RCND) rate base and FVRB, and the differences:

Summary of Rate Base	UNS Gas	RUCO	Difference
Original Cost Rate Base	$ 182,293,106	$ 179,884,439	$ (2,408,667)
RCND Rate Base	$ 329,266,770	$ 325,871,264	$ (3,395,506)
Fair Value Rate Base	$ 255,779,939	$ 252,877,851	$ (2,902,088)

Adjusted Net Operating Income

The following adjustments to UNSG's proposed revenues, expenses and net operating income should be made:

Summary of RUCO Adjustments to Net Operating Income

Adj No.	Description		Pre-Tax Operating Income or Expense Adjustment		Net Operating Income Adjustment
C-1	Gas Retail Revenue	$	516,003	$	316,836
C-2	Depreciation & Property Taxes for CWIP	$	95,042	$	58,358
C-3	Incentive Compensation	$	152,511	$	93,645
C-4	Stock-Based Compensation Expense	$	266,399	$	163,574
C-5	Supplemental Executive Retirement Plan Expense	$	101,021	$	62,029
C-6	American Gas Association Dues	$	16,762	$	10,292
C-7	Outside Services Legal Expense	$	217,674	$	133,656
C-8	Fleet Fuel Expense	$	471,826	$	289,711
C-9	Rate Case Expense	$	158,333	$	97,220
C-10	Interest Synchronization	$	-	$	(30,215)
C-11	Property Tax Expense	$	230,913	$	141,785
C-12	2010 Pay Increase	$	250,622	$	153,887
Total of RUCO's Adjustments to Net Operating Income		$	2,477,106	$	1,490,778
	Company Proposed Net Operating Income	$	-	$	11,600,004
	Rounding	$	-	$	-
	Adjusted Net Operating Income per RUCO			$	13,090,782

I. INTRODUCTION

Q. Please state your name, position and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe Larkin & Associates.

A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 400 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. Mr. Smith, please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the Certified Public Accountant ("C.P.A.") examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed C.P.A. and attorney in the State of Michigan. I am also a Certified Financial Planner™ professional and a Certified Rate of Return Analyst ("CRRA"). Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association and the Society of Utility and Regulatory Financial Analysts ("SURFA"). I have also been a member of the American Bar Association (ABA), and the ABA sections on Public Utility Law and Taxation.

Q. Please summarize your professional experience.

A. Subsequent to graduation from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July, 1979. Before becoming involved in utility regulation where the majority of my time for the past 29 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions, and, where appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

I have performed work in the field of utility regulation on behalf of industry, state attorneys general, consumer groups, municipalities, and public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Indiana, Illinois, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington D.C., West

Virginia and Canada as well as the Federal Energy Regulatory Commission and various state and federal courts of law.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Attachment RCS-1 provides details concerning my experience and qualifications.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Residential Utility Consumer Office ("RUCO").

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes. I have previously testified before the Commission on a number of occasions. I testified before the Commission in Docket No. E-01345A-06-0009, involving an emergency rate increase request by Arizona Public Service Company ("APS" or "Company"), and APS' Docket Nos. E-01345A-05-0816, E-01345A-05-0826 and E-01345A-05-0827, concerning proceedings involving APS base rates and other matters. I also testified before the Commission in the last UNS Gas, Inc. rate case, Docket Nos. G-04204A-06-0463, G-04204A-06-0013 and G-04204A-05-0831, and in the last UNS Electric, Inc. rate case Docket No. E-04204A-06-0783, as well as the last Southwest Gas Corporation rate case, G-01551A-07-0504.

Q. What is the purpose of the testimony you are presenting?

A. The purpose of my testimony is to address the rate base, adjusted net operating income and revenue requirement proposed by UNS Gas, Inc. ("UNSG", "UNS Gas," or "Company").

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachments RCS-2 through RCS-6 contain the results of my analysis and copies of selected documents that are referenced in my testimony, respectively.

II. REVENUE REQUIREMENT

Q. What issues are addressed in your testimony?

A. My testimony addresses the Company's proposed revenue requirement and selected other issues.

Q. What revenue increase has been requested by UNSG?

A. UNSG is requesting an increase in base rate revenues of $9.480 million, or approximately 6.1% percent, based on adjusted gas retail revenues at current rates of $51.158 million. The revenue amount is from Company Schedule C-1 in UNSG's filing and is also shown on RUCO Schedule C on Attachment RCS-2.

Q. What revenue increase does RUCO recommend?

A. RUCO recommends a revenue increase of no more than $841,000 on adjusted fair value rate base. As shown on Schedule A, on original cost rate base (OCRB) my calculations show a jurisdictional revenue deficiency of $803,000.

A. Test Year

Q. What test year is being used in this case?

A. UNSG's filing is based on the historic test year ended June 30, 2008. RUCO's calculations use the same historic test year.

Q. Could you please discuss the test year concept?

A. Yes. In Arizona, a historic test year approach is used. Various adjustments are made to the historic test year amounts to ensure that there is a matching of investment, revenues and expenses. Rate base items, such as plant in service and accumulated depreciation, are based on the actual level as of the end of the historic test year. Several rate base items that tend to fluctuate from month to month, such as materials and supplies and prepayments, are based on a test year average level. Since end of test year net plant in service is used, revenues are annualized based on end of test year customer levels. Additionally, certain expenses, such as depreciation and payroll costs, are annualized based on end of test year levels. This is to ensure that the going-forward revenue and expense levels are matched with the investment (net plant-in-service) used to serve those customers.

As time goes forward, changes in the Company's cost structure will occur. For example, rate base will increase as new plant is added to serve new customers, revenue will increase as customers are added, expenses will fluctuate, etc. It is very important to be consistent with a test period approach to ensure that there is a consistent matching between investment, revenues and costs. Any adjustments that reach beyond the end of the historic test year must be very carefully considered before being adopted.

B. Summary of Company Proposed and RUCO Adjusted Revenue Requirement

Q. What did your review of UNSG's filing indicate?

A. As shown on Attachment RCS-2, Schedule A, column C, based on the weighted cost of capital recommended by RUCO witness William Rigsby for application to OCRB, and the adjustments to UNSG's rate base and net operating income recommended by myself, I have calculated a jurisdictional base rate revenue requirement deficiency on OCRB of $803,000. As also shown on Schedule A, page 1, column D, I have calculated a recommended base rate increase of $841,000 using a fair value rate of return (FVROR) of

5.38. UNSG should receive a base rate increase of no more than $841,000 in this case. This represents an overall increase of approximately 1.63 percent.

C. Organization of RUCO Accounting Schedules

Q. How are RUCO's accounting schedules organized?

A. RUCO's accounting schedules are presented in Attachment RCS-2. They are organized into summary schedules and adjustment schedules. The summary schedules consist of Schedules A, A-1, B, B.1, C, C.1 and D. Attachment RCS-2 also contains rate base adjustment Schedules B-1 through B-6[1] and net operating income adjustment Schedules C-1 through C-12.

Q. What is shown on Schedule A of Attachment RCS-2?

A. Attachment RCS-2 presents the RUCO Accounting Schedules and revenue requirement determination. Schedule A presents the overall financial summary, giving effect to all the adjustments I am recommending in my testimony. This schedule presents the change in the Company's gross revenue requirement needed for the Company to have the opportunity to earn RUCO's recommended rate of return on RUCO's proposed Original Cost and Fair Value rate bases. The rate base and operating income amounts are taken from Schedules B and C, respectively. The overall rate of return on original cost rate base of 7.55 percent, as presented in the prefiled testimony of RUCO witness Rigsby, is provided on Schedule D for convenience, as are the derivation of RUCO's recommended fair value rate of return.

Columns A and B of Schedule A replicate UNSG's proposed calculations of the revenue deficiency. Columns C and D of Schedule A presents RUCO's determination of

[1] Currently, RUCO Adjustments B-4 and B-5 are placeholders, i.e., schedules reserved for an adjustment to be calculated at a later stage of proceeding, if necessary

the base rate revenue deficiency on OCRB and FVRB. Column C reflects Mr. Rigsby's recommended overall weighted cost of capital for OCRB. Column D uses RUCO's proposed fair value rate of return, which is explained in my testimony.

The operating income deficiency shown on line 5 of Schedule A is obtained by subtracting the operating income available on line 4 (operating income as adjusted) from the required operating income on line 3. Line 7 represents the gross revenue requirement, which is obtained by multiplying the income deficiency by the gross revenue conversion factor (GRCF). The derivation of the GRCF is shown on Schedule A-1.

Q. What is shown on page 2 of Schedule A?

A. Page 2 of Schedule A shows information concerning the potential impacts on UNSG's revenue deficiency in the current rate case that was considered by RUCO in developing the recommended FVROR recommendation. Similar to information presented by RUCO and Staff to the Commission in a recent remand proceeding, Docket No. W-02113A-04-0616, concerning Chaparral City Water Company, and in some other recent rate cases, I have also presented on Schedule A, page 2, in columns A through D various potential ways of determining a FVROR for UNSG, including:

- Calculation 1 - Reduce Recommended OCRB-Based Return on Equity for Estimated Inflation
- Calculation 2 - Reduce Recommended OCRB-Based Overall Rate of Return for Estimated Inflation
- Calculation 3 - With Fair Value Rate Base Increment at Zero Cost
- Calculation 4 - With Fair Value Rate Base Increment at 1.25%

The details for each FVROR calculation are shown on Schedule D, page 2.

On Schedule A, page 2, in column E, I also present RUCO's ultimate recommendation of the FVROR and the resulting base rate revenue deficiency. RUCO's recommendation falls within the range of FVRORs developed using various calculation methods, and is near, but not at the low end of that range. I believe that this information and RUCO's recommended FVROR in the current UNSG rate case that was made after considering these alternatives appropriately fulfills the requirement of the Arizona Constitution that the Commission must base rates on a utility's fair value.

Q. What is shown on Schedule A-1?

A. Schedule A-1 shows the derivation of the GRCF. The GRCF is used to convert the net operating income deficiency into a revenue deficiency amount.

Q. How does the GRCF recommended by RUCO compare with the GRCF contained in UNSG's filing?

A. As shown on Schedule A-1, RUCO recommends a GRCF of 1.636582. Other than carrying out two extra decimal places for slightly improved accuracy, this is essentially the same as the GRCF of 1.6366 used in UNSG's filing.

Q. What is shown on Schedule B?

A. Schedule B presents UNSG's proposed adjusted test year Original Cost and Fair Value rate base and RUCO's proposed adjusted test year Original Cost and Fair Value rate base. The beginning rate base amounts presented on Schedule B are taken from the Company's filing for the test year, specifically UNSG Schedule B-1. RUCO's recommended adjustments to rate base are summarized on Schedule B.1. I have prepared a Schedule B.1 for adjustments to UNSG's proposed original cost rate base. Because there is only one adjustment that differs between OCRB and Reconstruction Cost New Depreciated (RCND) rate base, I have only prepared one Schedule B.1, which shows OCRB amounts.

I address the difference in the OCRB and RCND amount used by the Company for CWIP/post test year plant in a subsequent section of my testimony.

Schedules B-1 through B-6 provide further support and calculations for the rate base adjustments RUCO is recommending.

Q. How was the fair value basis of rate base determined?

A. As shown on Attachment RCS-2, Schedule B, the fair value rate base was determined by averaging Original Cost and Reconstruction Cost New Depreciated (RCND) rate base information. For purposes of this presentation, I have used the Company's OCRB and RCND information as the starting point for RUCO's derivation of the fair value rate base.

Q. What is shown on Schedule C?

A. The starting point on Schedule C is UNSG's adjusted test year net operating income, as provided on Company Schedule C-1. RUCO's recommended adjustments to UNSG's adjusted test year revenues and expenses are summarized on Schedule C.1. Each of the adjustments are discussed in my testimony.

Schedules C-1 through C-12 provide further support and calculations for the net operating income adjustments RUCO is recommending.

Q. What is shown on Schedule D?

A. Schedule D, page 1, summarizes the capital structure and cost of capital that was proposed by UNSG and the capital structure and cost of capital that is recommended by RUCO witness Rigsby. As noted above, Schedule D, page 2, also presents four alternative calculations of a FVROR that were considered by RUCO in developing RUCO's recommended FVROR for use with the RUCO's adjusted fair value rate base.

Q. What is shown on Schedule D, page 1, lines 7-10?

A. On its Schedule D-1, UNSG purported to be requesting a return on equity ("ROE") of 11.0 percent, and an overall rate of return of 8.75 percent. However, on its Schedule A-1, line 7, UNSG has applied an overall rate of return of 9.54 percent to its proposed OCRB. On Schedule D, I have shown a calculation based on the capital structure UNSG used for developing its recommended rate of return of 9.54 percent on OCRB. This calculation shows that the equivalent return on equity ("ROE") implicit in UNSG's request for 9.54 percent on OCRB is an ROE of 12.58 percent, as summarized below:

UNS Gas Proposed to Show Equivalent Requested ROE

Capital Source	Capitalization Percent	Cost Rate	Weighted Avg. Cost of Capital
Long-Term Debt	50.01%	6.49%	3.25%
Common Stock Equity	49.99%	**12.58%**	6.29%
Overall Cost of Capital	100.00%		9.54%

D. Return on Fair Value Rate Base

Q. Has the Commission's traditional calculation of return on fair value rate base been called into question by a recent Court of Appeals decision?

A. Yes. The Commission's traditional calculation of return on fair value rate base calculation has been called into question by a recent Arizona Court of Appeals ruling involving Chaparral City Water Company. In that ruling, the Arizona Court of Appeals found that Staff's determination of operating income in that case had ignored fair value rate base, and that the Commission must use fair value rate base to set rates per the Arizona Constitution.

Q. What guidance for calculating the return on fair value rate base does that Court of Appeals decision provide?

A. First, the Court of Appeals specifically stated that the Commission was <u>not</u> bound to apply an authorized rate of return that was developed for use with an original cost rate base, without adjustment, to the fair value rate base. Page 9 of the Court of Appeals decision stated that: "Chaparral City … asks that the Commission be directed to apply the 'authorized rate of return' to the fair value rate base rather than to the OCRB, as Chaparral City contends was done here." At page 13, paragraph 17, the Court of Appeals decision stated as follows: "The Commission asserts that it was not bound to use the weighted average cost of capital as the rate of return to be applied to the FVRB. The Commission is correct." Thus, the Court of Appeals clearly stated that the Commission is <u>not</u> bound to apply to the FVRB the same weighted average cost of capital that was developed for application to the OCRB.

At pages 13-14, paragraph 17, the Court of Appeals decision stated that: "… the Commission cannot ignore its constitutional obligation to base rates on a utility's fair value. The Commission cannot determine rates based on the original cost, or OCRB, and then engage in a superfluous mathematical exercise to identify the equivalent FVRB rate of return. Such a method is inconsistent with Arizona law." At page 13, the decision states: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology."

Q. **Was a remand proceeding established by the Commission to address the calculation of the return on fair value rate base, i.e., to address the ruling in the Court of Appeals decision?**

A. Yes. The Commission reopened Docket No. W-02113A-04-0616 to address such issues in a Chaparral City remand proceeding and, on July 28, 2008, issued Decision No. 70441. In Decision No. 70441, the Commission determined the rate of return on FVRB that was reasonable and appropriate for Chaparral City, noting that there are many methods the

Commission can use to determine an appropriate FVROR, including adjusting the weighted average cost of capital ("WACC") to exclude the effect of inflation on the cost of equity, and that the adopted FVROR fell within the range of recommendations in that proceeding and reflected the Commission's exercise of its expertise and discretion in the ratemaking process.[2]

Q. How has RUCO addressed the ruling in the Court of Appeals decision for purposes of the current UNSG rate case?

A. In view of the Court of Appeals decision in the Chaparral City case, RUCO has appropriately adjusted the weighted cost of capital to derive a FVROR to apply to the utility's FVRB. My direct testimony in the instant rate case describes RUCO's derivation of the fair value return on fair value rate base calculations in view of the Court of Appeals decision concerning Chaparral and the Commission's Decision No. 70441 in the Chaparral remand case, as described above.[3] My Attachment RCS-2, Schedule D, page 2, shows the derivation of four FVROR calculations that were considered by RUCO. My Attachment RCS-2, Schedule A, page 2, in columns A through D, summarizes the resulting revenue deficiencies that would be produced in the current UNSG rate case from each of those FVROR figures. Schedule A, page 2, Column E shows RUCO's recommended FVROR and the resulting revenue deficiency. This FVROR recommendation was also applied to the FVRB on Schedule A, page 1, column D.

III. RATE BASE

Q. Have you prepared a schedule that summarizes RUCO's proposed adjustments to rate base?

[2] See, e.g., Decision No. 70441 at page 41, Finding of Fact Nos. 16 and 17.
[3] See, e.g., the preceding discussion, including the description of the calculations shown on Schedule A, page 2, at pages 7-8 of this testimony.

A. Yes. As noted above, the adjusted rate base is shown on Schedule B and the adjustments to UNSG's proposed rate base are shown on Schedule B.1. A comparison of the Company's proposed rate base and RUCO's recommended rate base on an Original Cost and Fair Value basis is presented below:

Summary of Rate Base	UNS Gas	RUCO	Difference
Original Cost Rate Base	$ 182,293,106	$ 179,884,439	$ (2,408,667)
RCND Rate Base	$ 329,266,770	$ 325,871,264	$ (3,395,506)
Fair Value Rate Base	$ 255,779,939	$ 252,877,851	$ (2,902,088)

ADJUSTMENTS TO ORIGNAL COST RATE BASE

Q. Please discuss RUCO's adjustments to UNSG's proposed original cost rate base.

A. RUCO has made five adjustments to UNSG's proposed original cost rate base. These have been designated as RUCO Adjustments B-1 through B-6. Each adjustment is discussed below.

B-1 Construction Work in Progress/Post Test Year Plant

Q. Please explain the adjustment shown on Schedule B-1.

A. UNS Gas has proposed to include $1.528 million of Post Test Year Non-Revenue Producing Plant in Service (i.e., Construction Work in Progress ("CWIP")) in rate base. RUCO adjustment B-1 removes that amount of CWIP from rate base.

Q. Please discuss UNS Gas' reason for requesting the inclusion of CWIP in rate base.

A. As described in the testimony of UNS Gas witness Dallas Dukes, the inclusion of post test year non-revenue producing plant in rate base will help the Company begin recovering its investment and an opportunity at earning a reasonable return in a more equitable time frame.

Q. Is inclusion of CWIP in rate base up to the discretion of the Commission?

A. Yes, it is. RUCO's understanding is, in specific instances, the Commission has allowed a utility to include CWIP in rate base, but the Commission's general practice has been to not allow CWIP to be included in rate base. As such, the Commission denied the Company's request for CWIP in rate base in its last rate case.[4]

Q. Does RUCO agree with the proposal of UNS Gas to include CWIP in rate base in the current case?

A. No. In general, RUCO does not favor inclusion of CWIP in rate base unless the utility demonstrates compelling reasons to justify this exceptional ratemaking treatment. For a number of reasons, including the following, RUCO does not support UNS Gas' request for rate base inclusion of CWIP/post test year plant in the current case:

1) Inclusion of CWIP in rate base is an exception to the Commission's normal practice, and UNS Gas has not met its burden of proof showing why it requires such an exceptional ratemaking treatment.

2) The CWIP was not in service at the end of the test year. As of June 30, 2008, the construction projects were not serving customers.

3) The Company has not demonstrated that its June 30, 2008 CWIP balance was for non-revenue producing and non-expense reducing plant. Much of the construction

[4] Decision No. 70011, Docket No. G-04204A-06-0463

appears to be for mains and services which can be related to serving customer growth, and/or can reduce expenses for maintenance.

4) Revenues have not been extended beyond the test year to correspond with customer growth. Hence, including the investment in rate base, without recognizing the incremental revenue it supports, would be imbalanced.

Q. Please elaborate on how including CWIP in rate base is an exceptional ratemaking treatment and why the circumstances in this case do not warrant such treatment.

A. CWIP, as the title designates, is not plant that is completed and providing service to ratepayers during the test year. During the test year, it was not used or useful in delivering gas service to the Company's customers. The ratemaking process is predicated on an examination of the operations of a utility to insure that the assets upon which ratepayers are required to provide the utility with a rate of return are prudently incurred and are both used and useful in providing services on a current basis. Facilities in the process of being built are not used or useful. The ratemaking process therefore excludes CWIP from rate base until such projects are completed and providing service to ratepayers in the context of a test year that is being used for determining the utility's revenue requirement. In the current UNS Gas rate case, the test year is June 30, 2008, and the construction projects the Company seeks to include in rate base were not providing service during that period. As a general ratemaking principle, such CWIP should be excluded from rate base.

Furthermore, some of the facilities that are being constructed and are included in CWIP will be used subsequent to the test year ended June 30, 2008 to serve additional customers.

It would not be appropriate to include the investment that will serve those new customers without also including the revenues that would be received from those customers. In other words, allowance of CWIP in rate base would result in a mismatch in the ratemaking process.

Additionally, some of the plant being added, such as main replacements, could result in a reduction in maintenance expenditures which would not be reflected in the test year. The inclusion of CWIP in rate base, therefore, creates an imbalance in the relationships between rate base serving customers and the revenues being provided to the utility from customers who were taking service during the test year. Consequently, CWIP should not be allowed in rate base unless there are very compelling circumstances which would warrant an exception to the general rule[5]. In the current case, UNS Gas has not demonstrated convincingly that it requires an exception to the Commission's standard ratemaking treatment of excluding CWIP from rate base. It is not appropriate to include the CWIP in rate base, particularly as the projects may result in additional revenues or cost savings which have not been reflected in the test year ended June 30, 2008.

Q. How does UNS Gas accrue a return on construction projects?

A. UNS Gas accrues a return, representing its financing costs during the construction period, called Allowance for Funds Used During Construction (AFUDC). This AFUDC return accounts for the utility's financing cost during the construction period. Then, when the

[5] RUCO is aware of only one instance in which the Commission has allowed CWIP in rate base. That occurred in the early 1980s when the Commission considered the costs associated with the Palo Verde Nuclear Plant. Because the up-front costs were so great, the Commission allowed CWIP in rate base in order for the plant to be built.

plant is placed into service, the AFUDC becomes part of the cost of the plant and is depreciated.

Q. How does plant that is placed into service between rate case test years typically get reflected in the regulatory process?

A. If the plant is used to serve new customers, the utility receives revenue from those customers. If the plant helps the utility reduce expenses, such as maintenance, the utility benefits from such cost reductions during the intervening period. Once the plant is recognized in rate base in a test year, and rates are reset, the utility earns a cash return on the plant investment, less accumulated depreciation. The related revenues and expense impacts, including known and measurable expense reductions enabled by the plant, are then also recognized in the ratemaking process.

Q. Did the Commission address this issue in UNS Gas' last rate case?

A. Yes. The Commission's decision in Decision No. 70011 addressed the issue of post-test year plant at pages 7-8, and reached the following conclusion:

> We agree with Staff that post-test-year plant should not be included in rate base for the same reasons stated above with respect to the Company's request for CWIP. Although the Commission has allowed post-test-year plant in several prior cases involving water companies, it appears that the issue was developed on the record in those proceedings in a manner that afforded assurance that a mismatch of revenues did not occur. For example, in Decision No. 66849 (March 19, 2004), we stated that "we do not believe that adoption of this method would result in a mismatch because the post-test-year plant additions are revenue neutral (i.e., not funded by CIAC or AIAC)" (Id. at 5). In the instant case, however, the Company's request appears to be simply a fallback to its CWIP position, and there is no development of the record to support inclusion of the post-test-year plant. The entirety of UNS's argument consists of two questions in Mr. Grant's direct testimony, which essentially provided that: the Commission has approved post-test-year plant in some prior cases, UNS is experiencing a high customer growth

> rate, and therefore the Company is entitled to inclusion of post-test-year plant if the Commission denies CWIP (Ex. A-27 at 28-29). Even if we were inclined to recognize post-test-year plant in this case, there is not a sufficient basis upon which to evaluate the reasonableness of the request (i.e., whether a mismatch would exist). We therefore deny the Company's proposal on this issue.

Q. Please summarize your adjustment to rate base for CWIP/Post Test Year Plant.

A. As shown on Schedule B-1, UNS Gas' proposed rate base is reduced by $1.528 million to remove the CWIP/ Post Test Year Plant.

Q. Does your adjustment to remove CWIP from rate base affect UNS Gas' expenses?

A. Yes. UNS Gas has proposed to treat CWIP at the end of the test year as if it were plant in service. Consistent with that, UNS Gas has included depreciation and property tax expense associated with CWIP in the test year. Consistent with RUCO's recommendation that CWIP not be included in rate base, RUCO adjustment C-2, which is described in a subsequent section of my testimony, removes the related UNS Gas adjustments for depreciation and property tax expense.

B-2 Customer Advances for Construction

Q. Please explain RUCO Adjustment B-2.

A. This adjustment decreases rate base by $589,152 to reflect the full end-of-test-year balance for Customer Advances.

Q. Why has UNSG sought to remove $589,152 from Customer Advances?

A. Mr. Dukes' direct testimony at page 12 claims that this amount of Customer Advances relates to projects that are not in rate base as of the end of the test year.

Q. Was a similar claim made by UNSG in its last rate case?

A. Yes. As one of UNSG's supporting arguments for its attempt to include CWIP in rate base, UNSG had also attempted to have a portion of Customer Advances excluded from the determination of rate base, using similar arguments from the prior case.

Q. Did the Commission make that UNSG-proposed adjustment in UNSG's last rate case?

A. No. In UNSG's last rate case, the Commission appropriately deducted the full amount of Customer Advances from rate base. This issue is addressed in Decision No. 70011 at pages 8-10, and the Commission reached the following conclusion:

> We agree with Staff and RUCO that advances represent customer-supplied funds that are properly deducted from the Company's rate base. Indeed, the Commission's own rules contemplate that such a deduction is required, as Staff witness Smith testified. Had UNS not requested the inclusion of CWIP in rate base, a ratemaking treatment that is only afforded under extraordinary circumstances (and apparently has not occurred for more than 20 years), there would presumably not have been an issue raised by the Company with respect to an alleged "mismatch" between exclusion of CWIP and deducting advances from rate base. The Company's attempt to frame this issue as one in which it is being treated in a discriminatory manner is unpersuasive.
>
> As we have stated in prior cases, regulated utility companies control the timing of their rate case filings and should not be heard to complain when their chosen test periods do not coincide with the completion of plant that may be considered used and useful and therefore properly included in rate base. We believe our conclusions regarding UNS's CWIP-related proposals are entirely consistent with the treatment that has been afforded to other utility companies regulated by the Commission and provide a result that is fair to both the Company and its customers.

Q. Do you agree with UNSG's claim that some Customer Advances should be excluded in the determination of rate base?

A. No. Because Customer Advances represent non-investor supplied capital, they should be reflected as a deduction to rate base. Additionally, research conducted in the context of

UNSG's last rate case did not reveal any instance in which CWIP for a major utility was excluded from rate base and customer advances were not also reflected as a deduction to rate base. Additionally, the Commission's rules at A.A.C. R14-2-103, Appendix B, Schedule B-1, require companies to reflect Advances as a deduction from rate base.

Q. Please summarize your adjustment to rate base for Customer Advances.

A. The rate base deduction for Customer Advances should reflect the full end-of-test year amount. For the reasons described above, the adjustment proposed by UNSG should be rejected. Customer Advances proposed by UNSG should be increased by $589,152 and rate base reduced by this amount.

B-3 Prepayments

Q. What adjustment has the Company made to rate base for Prepayments?

A. As shown on UNS Gas Schedule B-5, page 2 of 3, the Company has proposed to increase rate base by $95,671 for the use of a 13-month average for Prepayments, rather than using the end-of-test year balance.[6]

Q. Do you agree with that Company-proposed adjustment?

A. No. While the use of an average balance can be appropriate for ratemaking purposes, virtually all of the other rate base balances in this case, including those for Plant in Service, Accumulated Depreciation, Customer Advances, Customer Deposits, etc., are year-end balances. Unless there is a compelling reason to deviate from consistent use of year-end balances, which I do not believe there is for Prepayments, year-end balances should be used for consistency. The Company's proposed adjustment to Prepayments is

[6] UNS Gas also proposes a similar adjustment for Materials and Supplies, but that adjustment is only $728 on a M&S balance of over $2 million and is therefore being ignored on the basis of immateriality.

inconsistent with the majority of the other rate base components, which are based on end-of-test-year balances, is basically unnecessary and should be rejected.

B-4 Cash Working Capital

Q. Have you reviewed the Company's request for a cash working capital allowance?

A. Yes. The Company has proposed a cash working capital allowance of approximately $1,568, i.e., under $1,600.

Q. What is cash working capital?

A. Cash working capital is the cash needed by the Company to cover its day-to-day operations. If the Company's cash expenditures, on an aggregate basis, precede the cash recovery of expenses, investors must provide cash working capital. In that situation a positive cash working capital requirement exists. On the other hand, if revenues are typically received prior to when expenditures are made, on average, then ratepayers provide the cash working capital to the utility, and the negative cash working capital allowance is reflected as a reduction to rate base. In this case, the cash working capital requirement is a reduction to rate base as ratepayers are essentially supplying these funds.

Q. Does UNSG have a positive or negative cash working capital requirement?

A. Based on its calculations, UNSG has a slight positive cash working capital requirement of under $1,600. In other words, ratepayers are essentially supplying the funds used for the day-to-day operations of the Company approximately at the same time UNS Gas is paying for the cash expenditures. On average, revenues from ratepayers are received virtually on the same day as when the utility pays the associated expenditures.

Q. Did UNSG present a lead/lag study in support of its cash working capital requirement?

A. Yes, UNSG performed a lead/lag study to calculate the cash working capital requirement in this case. The Company also provided its lead/lag study calculations with the work papers provided in the case.

Q. Has UNSG made any revisions to the cash working capital calculation included in its filing?

A. No, none of which I am aware.

Q. Are you recommending any revisions to UNSG's cash working capital request?

A. Not at this time. However, in a later filing, such as in surrebuttal, I would propose to update UNSG's cash working capital allowance to reflect the impact of RUCO's adjustments to operating expenses and revenue based taxes, and to synchronize the calculation of cash working capital with RUCO's recommended revenue increase.[7] I have reserved Schedule B-4 for a cash working capital update.

B-5 Customer Deposits

Q. Are you proposing an adjustment for Customer Deposits at this time?

A. No. Customer Deposits, an offset to rate base, also have fluctuated from month to month, as shown in UNSG's response to Staff data request TF 6-28. The test year average for Customer Deposits would be approximately $3.034 million, versus the June 30, 2008 balance of only $2.609 million used by UNSG[8]. If Customer Deposits were also to be

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[7] Such synchronization has not yet been reflected at this time, but would be incorporated in RUCO's surrebuttal filing.

[8] The September 2007 amount for customer deposits was missing from UNSG's response to Staff data request TF 6.28(c).

calculated using a test year average, rather than using the year-end balance, an adjustment for this would decrease rate base by approximately $425,000.

I am recommending that a year-end balance be used for Customer Deposits. UNSG's filing reflected the use of a year-end balance. However, if other rate base components, such as Prepayments, are going to be adjusted using a 13-month average, then, for consistency with such an adjustment, Customer Deposits, which have also fluctuated during the test year, should also be reflected in rate base on a 13-month average basis.

B-6 Accumulated Deferred Income Taxes

Q. Please explain the adjustment to Accumulated Deferred Income Taxes ("ADIT") that were included in rate base by UNSG for Accounts 190 and 283.

A. This adjustment is shown on Schedule B-6. The following items reflected in Accounts 190 and 283 are removed:

- Dividend Equivalents
- Restricted Stock
- Restricted Stock - Directors
- Stock Options
- Vacation
- Pension

Each of these items has no corresponding liability that is offsetting rate base. The removal of these items decreases rate base by $423,669. ADIT for a particular item is generally included in rate base as an offset to the related item generating the deferred taxes that is included in rate base, and is excluded if the related item is excluded from rate base. The ADIT components for which there is no corresponding asset or liability should be removed from rate base. Additionally, consistent with my use of the full test-year-end balance of Customer Advances in rate base, I have reversed UNSG's adjustment that had decreased the ADIT balance in Account 190 by $227,413. That reversal increases rate base by the $227,413 of ADIT related to the Customer Advances. The net adjustment to ADIT shown on Schedule B-6 decreases rate base by $196,256.

RECONSTRUCTION COST NEW DEPRECIATED RATE BASE

Q. Please describe RUCO's adjustments to RCND rate base.

A. For the most part, RUCO's adjustments to UNSG's proposed RCND rate base are the same amounts as RUCO's adjustments to OCRB. On its Schedule B-3, page 2, however, UNSG used an amount of $2.514 million for its adjustment for CWIP/post-test year plant, versus the $1.528 million for this adjustment shown on UNSG's Schedule B-2, page 2. Consequently, I have removed the $2.514 million from RCND rate base, as shown on Schedule B.

Q. Do you have any other comments about the significant difference between the OCRB and RCND adjustment amounts used by UNSG for this item?

A. Yes. UNS Gas has not justified how the RCND amount for this item would be so much higher than the OCRB amount. This is essentially for end-of-test year CWIP that UNSG wants to treat as plant in service, so presumably the OCRB and RCND amounts should be the same.

IV. ADJUSTMENTS TO OPERATING INCOME

Q. Please describe how you have summarized RUCO's proposed adjustments to operating income.

A. Schedule C summarizes RUCO's recommended net operating income. Schedule C.1 presents RUCO's recommended adjustments to Arizona test year revenues and expenses.

The impact on state and federal income taxes associated with each of the recommended adjustments to operating income are also reflected on Schedule C.1. UNSG's proposed adjusted test year net operating income is $11.600 million, whereas RUCO's recommended adjusted net operating income is $13.091 million. The recommended adjustments to operating income are discussed below in the same order as they appear on Schedule C.1.

C-1 Revenue Annualization

Q. Please explain RUCO Adjustment C-1.

A. This adjustment reverses the Company's proposed customer annualization adjustment, which had decreased test year revenue by approximately $516,000.

Q. How is a customer annualization typically used in a utility rate case?

A. Where a utility is growing and having to add plant during a test year to serve additional customers, a revenue annualization adjustment is typically employed in order to capture the impact on revenue from customer growth that has occurred and to better match the revenue with the test year plant that has been added to serve the new customers. The revenue growth that relates to the addition of customers is captured in an adjustment to increase revenue that is related to the increased plant that has been added to serve additional customers during the test year.

Q. How has the customer annualization been applied by UNS Gas in the current rate case?

A. While the Company employed an annualization method similar to the one that was used in its last rate case, the rote application of such method in the current case is decreasing test year revenues. Moreover, the decrease in revenue produced by the Company's calculation appears to be related to customer seasonality rather than a permanent decline in customer count during the test year, and therefore should not be adopted because it would understate test year and going-forward revenues.

Q. Hasn't UNS Gas experienced customer growth?

A. Yes, it has. Year after year, UNSG's number of average customers has been increasing. This holds true for the test year as well. Consequently, because customer counts year-over-year have been increasing for the past several years including the test year, test year revenues should not be decreased based on the misapplication of an annualization adjustment. In other words, while the application of an annualization adjustment may have made sense and been appropriate in UNSG's last rate case to account for customer growth that had occurred during that test year which ended December 31, 2005, rote application of such a method in the current case produces results that do not make sense because it essentially assumes that UNSG is losing residential and commercial customers, when clearly that is NOT the case.

Q. What year-over-year increases has UNS Gas experienced for residential customers?

A. The year-over-year increases UNS Gas has experienced for residential customers are summarized in the following table:

Period	Average Number of Residential Customers	Change
2004	118,967	
2005	124,452	5,484
2006	129,054	4,602
2007	131,788	2,734
TYE 6/2008	132,347	559
Avg 7/08 - 3/09	132,601	254

Each year, UNS Gas has gained residential customers. Moreover, even if one looks at comparable periods ending in June 30 through the current test year ended June 30, 2008, UNS Gas has gained residential customers in each year. Information comparing the number of UNS Gas' average residential customers for 12-month periods ending with June 30 is summarized in the following table:

Period	Average Number of Residential Customers	Change
12 Months Ended:		
6/30/2005	121,703	
6/30/2006	126,852	5,149
6/30/2007	130,763	3,911
TYE 6/2008	132,347	1,585

While growth in the test year has slowed compared with the robust growth of previous years, there was still growth of residential customers.

Q. What year-over-year increases has UNS Gas experienced for commercial customers?

A. The year-over-year increases UNS Gas has experienced for commercial customers are summarized in the following table:

Period	Average Number of Commercial Customers	Change
2004	10,654	
2005	10,883	229
2006	11,158	275
2007	11,387	229
TYE 6/2008	11,446	60

Each year, UNS Gas has gained commercial customers. Information comparing the number of UNS Gas' average commercial customers for 12-month periods ending with June 30 is summarized in the following table:

Period	Average Number of Commercial Customers	Change
12 Months Ended:		
6/30/2005	10,764	
6/30/2006	10,989	225
6/30/2007	11,293	304
TYE 6/2008	11,442	149

Looking at comparable periods ending in June 30, through the current test year ended June 30, 2008, UNS Gas has gained commercial customers in each year.

Q. What do you conclude from this information?

A. I conclude that UNS Gas has added, on average, both residential and commercial customers in each and every year, including the test year. Consequently, an adjustment to decrease test year revenue would understate test year and going-forward revenues and be inappropriate and should be rejected. Test year revenue of $516,000 should not be removed as proposed by UNSG. RUCO adjustment C-1 restores this amount of actual test year revenue to the test year.

C-2 Depreciation & Property Taxes for CWIP/Post Test Year Plant

A. This adjustment is related to RUCO Adjustment B-1, which removed UNSG's request for inclusion in rate base of CWIP/Post Test Year Plant. It removes $58,107 of Depreciation Expense, $11,351 of O&M Expense related to depreciation on transportation equipment, and $25,584 of Property Tax Expense related to the adjustment to remove UNSG's request for CWIP/Post Test Year Plant in Service. In total, UNSG's expenses are reduced by $95,042.

Q. How did you determine the recommended assessment rate for property taxes?

A. This adjustment reflects the known statutory assessment ratio of 22 percent applicable for 2009, when rates in this case are expected to be effective. Section 42-15001 of the Arizona State Legislature provides the current percentages for property tax assessments. The assessment rate schedule provides for decreasing the 25 percent rate applicable in 2005 by 0.5 for the year 2006 and 1.0 percent each year thereafter until a 20 percent rate is attained in 2011. The Company's calculation also used a 22 percent assessment rate.

C-3 Incentive Compensation Expense

Q. Please explain Staff Adjustment C-3.

A. This adjustment provides for the allocation of 50 percent of the test year expense for the incentive compensation to shareholders. Test year expense for incentive compensation expense proposed by UNSG is reduced by $140,484. Related payroll tax expense is decreased by $12,027.

Q. Please explain why a 50 percent allocation to shareholders is appropriate for an incentive compensation program.

A. In general, incentive compensation programs can provide benefits to both shareholders and ratepayers. The removal of 50% of the incentive compensation expense, in essence, provides an equal sharing of such cost, and therefore provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Both shareholders and ratepayers stand to benefit from the achievement of performance goals; however, there is no assurance that the award levels included in the Company's proposed expense for the test year will be repeated in future years.

Q. Please briefly discuss the key provisions of the incentive compensation program.

A. The Company's response to Staff data request TF 6.64 states UNS Gas non-union employees participate in UniSource Energy Corporation's ("UniSource") Performance Enhancement Plan ("PEP"). The structure of the PEP determines eligibility for certain bonus levels by measuring UniSource's performance in three areas: (1) financial performance; (2) operational cost containment; and (3) core business and customer service goals. Levels of achievement in each area are assigned percentage-based "scores." Those scores are combined to calculate the final payout level. The amount made available for bonuses pursuant to the PEP may range from 15 to 150 percent of the targeted payout level. The financial performance and operational cost containment components each make up 30 percent of the bonus structure, while the core business and customer service goals account for the remaining 40 percent.

As explained in the Company's response to Staff data request TF 6.64:

> The scores from each goal are totaled and then multiplied by the targeted bonus of each employee to determine the total available dollars to be paid out. Targeted bonus percentages, as a percent of base salary, range from 3% to 14% for regular unclassified employees, and 25% to 80% for Managers and Officers. Bonus percentages, as a percent of base salary, are used in the calculation of total available dollars, and actual awards may vary at management's discretion, based on individual employee contribution. If a payout is achieved, employee PEP bonuses will be distributed near the end of the first quarter the following year.

Q. Does UNSG recognize that its proposed treatment of incentive compensation expense in the current case represents a conscious deviation from principles and policies established in prior Commission Orders?

A. Yes. Data request TF 6.103 asked[9]:

> Are there any aspects of the Company's accounting adjustments and revenue requirement claim which represents a conscious deviation from the principles and

[9] See Attachment RCS-5.

> policies established in prior Commission Orders? If so, identify each area of deviation, and for each deviation explain the Company's perception of the principle established in the prior Commission orders, how the Company's proposed treatment in this rate case deviates from the principles established in the prior Commission orders, and the dollar impact resulting from such deviation. Show which accounts are affected and the dollar impact on each account for each such deviation.

UNSG's response to this data request states in part that: "In the prior Commission decision, 50% of the incentive compensation expense was excluded from revenue requirements. UNS Gas is requesting full recovery of the normal and recurring level of incentive compensation expense."

Q. What reasoning does UNSG give for its request to recover 100% of its incentive compensation expense despite prior Commission Orders?

A. In his Direct Testimony at page 21, Company witness Dukes stated that the Company's incentive compensation program is designed to award non-union employees for their contributions to the company.

Q. What criteria has the Commission found important in deciding issues concerning utility incentive compensation in recent cases?

A. The criteria the Commission has found important in deciding this issue in recent cases are described in various orders which have addressed the treatment of utility incentive compensation expense for ratemaking purposes. In Decision No. 68487 (February 23, 2006), the Commission adopted Staff's recommendation for an equal sharing of costs associated with the Southwest Gas Corporation's ("SWG") Management Incentive Plan ("MIP") expense. For example, in reaching its conclusion regarding SWG's MIP, the Commission stated in part on page 18 of Order 68487 that:

> We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the

> benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendations to be a reasonable resolution.

Mr. Dukes has not refuted the fact that both shareholders and ratepayers derive some benefit from incentive goals.

Q. Do UNSG's shareholders and customers both benefit from the achievement of incentive compensation program?

A. Yes. Shareholders benefit from the achievement of financial goals. Additionally, shareholders benefit from the achievement of expense reduction and expense containment goals between rate cases. Shareholders and ratepayers can both benefit from the achievement of customer service goals.

Q. How does the amount of UNSG's incentive compensation expense in the current case compare with the amount from UNSG's prior rate case?

A. The following table summarizes UNSG's incentive compensation (PEP) expense in the current case, the prior case (Docket No. G-04204A-06-0463), and the amount which was ultimately allowed in Decision 70011:

Line No.	Description	Amount	Source
1	Incentive compensation (PEP) included in current case	$ 280,968	Schedule C-3
2	Incentive compensation (PEP) expense requested in Docket No. G-04204A-06-0463	$ 126,859	Staff Witness Smith, Sch. C-6
3	Increase	$ 154,109	L1 - L2
4	Percent Increase	121.48%	L3/L2
5	Amount Allowed in Decision No. 70011	$ 63,430	Decision 70011

As shown in the above table, the Company's incentive compensation expense is significantly higher in the current rate case than it was in the prior UNSG rate case.

Q. **Have the facts changed materially since the last UNS Gas rate case that a different result concerning the sharing of incentive compensation expense should occur?**

A. No, I don't believe so. The rationale for the 50 percent allocation to shareholders of this expense in the current case appears to be consistent with the Commission's findings concerning SWG's MIP in Decision No. 68487, and findings about UNSG's incentive compensation expense in Decision No. 70011. In Decision No. 70011 (November 27, 2007), in the last UNS Gas rate case, Docket No. G-04204-06-0463 et al, the Commission stated in part on page 27 that:

> We believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program.

Q. **Did UNSG appeal Decision No. 70011?**

A. No.

Q. **Was an equal sharing of incentive compensation expense ordered in other recent Commission decisions in rate cases involving Arizona utilities?**

A. Yes. In Decision No. 70360 (May 27, 2008), in the recent UNS Electric, Inc. rate case, Docket No. E-04204A-06-0783, the Commission stated at page 21 that:

> Consistent with our finding in the UNS Gas rate case (Decision No. 70011, at 26-27), we believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program...Given that the arguments raised in the UNS Gas case are virtually identical to those presented in this case, we see no reason to deviate from that recent decision.

Finally, in Decision No. 70665 (December 24, 2008), in the most recent Southwest Gas Company rate case, Docket No. G-01551A-07-0504, the Commission stated at page 16 that:

> In the last Southwest Gas rate case, as well as several subsequent cases,[3] we disallowed 50 percent of management incentive compensation on the basis that such programs provide approximately equal benefits to shareholders and ratepayers because the performance goals relate to financial performance and cost containment goals as well as customer service elements. (Decision No. 68487 at 18.) In that Decision, we stated:
>
>> In Decision No. 64172, the Commission adopted Staff's recommendation regarding MIP expenses based on Staff's claim that two of the five performance goals were tied to return on equity and thus primarily benefited shareholders. We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendation to be a reasonable resolution.
>
> (Id.) We believe the same rationale exists in this case to adopt the position advocated by Staff and RUCO to disallow 50 percent of the Company's proposed MIP costs.[4]

[3]See UNS Gas, Inc., Decision No. 70011 (November 27, 2007) at 27; Arizona Public Service Co., Decision No. 69663 (June 28, 2007) at 27; and UNS Electric, Inc., Decision No. 70360 (May 27, 2008) at 21.
[4]On the same basis, we will also disallow 100 percent of the Southwest Gas stock incentive plan ("SIP"). The costs related to similar incentive plans were recently rejected for APS and UNS Electric. (See Ex. S-12 at 32-34.) As was noted in the APS case, stock performance incentive goals have the potential to negatively affect customer service, and ratepayers should not be required to pay executive compensation that is based on the performance of the Company's stock price. (Decision No. 69663 at 36.)

Q. Should the 50/50 ratepayer/shareholder sharing that the Commission applied to utility incentive compensation in UNSG's last rate case be modified to a 100 percent ratepayer responsibility for such cost based on the analysis presented by Mr. Dukes?

A. No. The 50/50 sharing of UNSG's incentive compensation program cost ordered by the Commission in Decision No. 70011 should continue to apply in the current UNSG rate case.

Q. Please summarize your recommendation concerning UNSG's incentive compensation expense.

A. I recommend continuing the 50 percent allocation for UNSG's incentive compensation expense to shareholders ordered by the Commission in Decision No. 70011. This results in a reduction to test year expense of $140,484.

C-4 Stock-Based Compensation Expense

Q. What amounts of stock-based compensation expense has UNSG included in the test year?

A. UNSG's response to data request RUCO 1.46 identifies $266,399 of stock-based compensation expense in the test year.

Q. For what types of stock-based compensation has UNSG included an expense in the test year?

A. UNSG has included an expense in the test year for the following types of stock-based compensation:

- Stock Option Expense
- Dividend Equivalents on Stock Units
- Performance Stock Award
- Dividend Equivalent on Stock Options
- Directors Stock Awards

As described in the Company's response to TF 6.92 and UniSource Energy's March 22, 2009 Proxy Report, the UNSG's parent company, UniSource Energy offers the following types of stock-based compensation:

Stock options

Stock options are offered as part of as part of UniSource Energy's long-term incentive program for officers. Options have an exercise price equal to the fair market value on the date of grant and a maximum term of ten years. The options vest at one-third increments beginning on the first anniversary of grant date.[10]

Performance share awards

Performance share awards reward achievement of financial performance objectives and/or shareholder value objectives. Performance share awards are paid in shares of UniSource Energy stock under a three year cycle. Performance goals are based on compound annual shareholder return. No dividends are paid on performance shares until earned and vested.

[10] Also see, e.g., UNSG's responses to Staff data request TF 6.92.

Directors stock awards

Non-employee directors receive an annual award in restricted stock units as follows:

- Directors serving on the date of the Annual Shareholders' meeting receive a grant on the date of that meeting. Any person who first becomes a director after the Annual Shareholders' meeting receives a grant on a date approved by the Compensation Committee. All restricted stock unit grants to directors vest at the earlier of the next annual meeting following grant date or the first anniversary of grant.
- The actual number of restricted stock units granted is calculated by dividing $45,000 by the closing price of our common stock on the date of grant.
- Vested stock unit grants must be deferred and distributed in January of the year following the year during which a director ceases to serve as a member of our Board. Deferred stock units accrue dividend equivalents during the deferral period. Deferral stock units are distributed in shares of Company stock.

Dividend equivalent on stock units and stock options

Under the Director's Deferred Compensation Plan ("DCP"), certain eligible officers and other employees selected for participation, and non-employee members of the Board, may elect to defer a percentage of the compensation of fees that would otherwise become payable to the individual for his services. Each participant in the DCP may elect that his deferrals be credited in the form of additional deferred shares instead of cash. Deferred shares accrue dividend equivalents, credited in the form of additional deferred shares, as dividends are paid by UniSource Energy on its issued and outstanding common stock. Each participant elects the time and manner of payment (lump sum or installments) of his deferred shares under the DCP.

Q. Did the Commission recently disallow another utility's stock based compensation in a recent decision?

A. Yes. In Decision No. 69663, from a recent APS rate case, the Commission adopted a Staff recommendation in that case where cash-based incentive compensation expense was allowed and stock-based compensation was disallowed. Additionally, page 36 of Decision No. 69663 indicates that the Commission rejected an argument by APS that the Commission not look at how compensation is determined or its individual components:

> "APS argues that the issue is whether APS compensation, including incentives, is reasonable. APS does not believe that the Commission should look at how that compensation is determined or its individual components, but rather should just look at the total compensation. The Company argues that the interests of investors and consumers are not in fundamental conflict over the issue of financial performance, because both want the Company to be able to attract needed capital at a reasonable cost."
>
> "We agree with Staff that APS' stock-based incentive compensation expense should not be included in the cost of service used to set rates. Contrary to APS' argument that we should not look at how compensation is determined, we do not believe rates paid by ratepayers should include costs of a program where an employee has an incentive to perform in a manner that could negatively affect the Company's provision of safe, reliable utility service at a reasonable rate. As testified to by Staff witness Dittmer and set out in Staff's Initial brief, "[e]nhanced earnings levels can sometimes be achieved by short-term management decisions that may not encourage the development of safe and reliable utility service at the lowest long-term cost. ... For example, some maintenance can be temporarily deferred, thereby boosting earnings. ... But delaying maintenance can lead to safety concerns or higher subsequent 'catch-up' costs." [cite omitted] To the extent that Pinnacle West shareholders wish to compensate APS management for its enhanced earnings, they may do so, but it is not appropriate for the utility's ratepayers to provide such incentive and compensation."

Thus, in Decision No. 69663, the Commission made an adjustment to disallow a portion of that utility's incentive compensation expense, specifically the stock-based compensation.

Q. Was stock-based compensation expense also disallowed in the Commission's recent decision in the rate case involving UNS Electric, Inc.?

A. Yes, it was. In Decision No. 70360 at page 22, the Commission, in referencing a similar decision regarding Southwest Gas Corporation as well as APS' last rate case stated:

> "For these same reasons, we agree with Staff that test year expenses should be reduced to remove stock-based compensation to officers and employees...The disallowance of stock-based compensation is consistent with the most recent rate case for Arizona Public Service Company (Decision No. 69663)."

Q. Please discuss the reasons for removing stock-based compensation.

A. Ratepayers should not be required to pay executive compensation that is based on the performance of the Company's (or its parent company's) stock price. Additionally, prior to being required to expense stock options for financial reporting purposes under Statement of Financial Accounting Standards No. 123 Revised (SFAS 123R), the cost of stock options was typically treated as a dilution of shareholders' investments, i.e., it was a cost borne by shareholders. While SFAS 123R now requires stock option cost to be expensed on a company's financial statements, this does not provide a reason for shifting the cost responsibility for stock options from shareholders to utility ratepayers.

Q. Please explain RUCO Adjustment C-4.

A. As shown on Schedule C-4, this adjustment decreases test year expense by $266,399 to reflect the removal of UNSG's stock option compensation expense that is allocated to Arizona operations. The expense of providing stock options and other stock-based compensation to officers, employees and directors beyond their other compensation should be borne by shareholders and not by ratepayers.

C-5 Supplemental Executive Retirement Plan Expense

Q. Please explain RUCO Adjustment C-5.

A. This adjustment removes 100% of the expense for the Supplemental Executive Retirement Plan ("SERP"). The SERP provides supplemental retirement benefits for select executives. Generally, SERPs are implemented for executives to provide retirement benefits that exceed amounts limited in qualified plans by Internal Revenue Service ("IRS") limitations. Companies usually maintain that providing such supplemental retirement benefits to executives is necessary in order to ensure attraction and retention of qualified employees. Typically, SERPs provide for retirement benefits in excess of the limits placed by IRS regulations on pension plan calculations for salaries in excess of specified amounts. IRS restrictions can also limit the Company 401(k) contributions such that the Company 401(k) contribution as a percent of salary may be smaller for a highly paid executive than for other employees.

Q. Has utility SERP expense been disallowed by the Commission in a series of recent rate cases?

A. Yes. In Decision No. 68487, February 23, 2006, in a Southwest Gas Corporation rate case, the Commission adopted a recommendation by RUCO to remove SERP expense. In reaching its conclusion regarding SERP, the Commission stated on page 19 of Order 68487 that:

> Although we rejected RUCO's arguments on this issue in the Company's last rate proceeding, we believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives 'whole' in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations

> applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers.

Q. Was SERP expense disallowed in the Commission's decision in the last rate case involving UNS Gas, Inc?

A. Yes, it was. See Decision No. 70011 at pages 27-29. Notably, at page 28 of that Decision, the Commission stated:

> … the issue is not whether UNS may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rationale on this issue in the most recent Southwest Gas rate case [See also Arizona Public Service Co., Decision No. 69663, at 27 (June 28, 2007), wherein SERP costs were excluded in their entirety.], and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.

Q. Was SERP expense also disallowed in the Commission's recent decisions in the rate cases involving UNS Electric, Inc.?

A. Yes, it was. In the recent UNS Electric, Inc. rate case, in Decision No. 70360 at page 22, referencing the above captioned quote, the Commission stated:

> *We see no reason to depart from the rationale on this issue in the most recent UNS Gas rate case, and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.*

The Commission's Decision No. 70665 (December 24, 2008) in the most recent Southwest Gas rate case, Docket No. G-01551A-07-0504, stated as follows on pages 17-18:

> We agree with Staff and RUCO that the SERP expenses sought by Southwest Gas should once again be disallowed. We do not believe any

material factual difference exists in this case that would require a result that differs from the Company's prior case. In that case, we stated:

> [W]e believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's *other* employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives "whole" in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers.

(Decision No. 68487 at 19.)

In the recent UNS Gas, APS, and UNS Electric cases, we followed the rationale cited above in disallowing SERP expenses. In Decision No. 70011, we indicated that SERP costs should not be recoverable and indicated:

> [T]he issue is not whether UNS may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rationale on this issue in the most recent Southwest Gas rate case, and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.

[Id. At 28, (footnote omitted).] For these reasons, we agree with the recommendations of Staff and RUCO that the request for inclusion in rates of SERP expenses should be denied. We therefore adopt the recommendations of Staff and RUCO on this issue.

Q. What adjustment related to UNSG's SERP expense do you recommend?

A. I recommend the adjustment to remove UNSG's expense for the SERP, which is shown on Schedule C-5 and reduces O&M expense by $101,021.

C-6 American Gas Association Dues

Q. Please explain RUCO's proposed adjustment for American Gas Association dues.

A. This adjustment is shown on Schedule C-6 and reduces test year expense by $18,678 to reflect the removal of 40 percent of AGA dues.

Q. How does RUCO's proposed adjustment for AGA dues compare with UNSG's proposed treatment of such dues?

A. As noted above, I recommend the removal of 40 percent of AGA core dues, while UNSG's filing reflected the removal of only 4 percent of the AGA dues.

Q. What information did UNS Gas provide concerning the specific benefits of AGA activities to the Company and Arizona ratepayers?

A. UNSG witness Gary A. Smith addresses AGA benefits at pages 9-14 of his direct testimony. The AGA does provide some benefit to the utilities that comprise its membership; however, this does not negate the fact that a significant portion of AGA expenditures are related to programs which should be disallowed for ratemaking purposes. I have attached to my testimony a listing and description of the AGA's functions as listed in the March 2005 Annual Audit report to the National Association of Regulatory Utility Commissioners (NARUC), and have identified the percentage of AGA activities related to each function.

Q. Does the information provided by UNSG show that 96 percent (100 percent minus the Company's 4 percent disallowance) of AGA dues-funded activities are beneficial to the Company and/or to its Arizona ratepayers?

A. No. UNS Gas has demonstrated that there is some benefit of AGA membership to the Company and to Arizona ratepayers from some of the AGA's functions. However, the Company has failed to demonstrate that ratepayers should fund activities conducted through an industry organization that would be subject to disallowance if conducted directly by the utility. The Company has failed to demonstrate that a disallowance of AGA dues of only 4 percent is adequate. As I will discuss below, other states have used a significantly higher disallowance percentage for gas utility AGA dues than UNSG is proposing here.

Q. To your knowledge what percentage disallowance for utility AGA dues has been used in other recent utility rate cases?

A. In the last UNS Gas rate case, as described on pages 32-33 of Decision No. 70011, UNS Gas had initially included $41,854 for AGA dues, and RUCO witness Moore recommended a partial disallowance of $1,523, based on an AGA/NARUC Oversight Committee Report indicating that 1.54 percent of AGA dues were for marketing and 2.10 percent of dues were for lobbying activities. UNS Gas agreed with that adjustment, and it was ultimately adopted by the Commission. At pages 33-34 of Decision No. 70011, however, the Commission also stated that:

> Mr. Smith raises a valid point regarding the nature of AGA dues and whether a higher percentage of such dues should be disallowed as related to activities that are not necessary for the provision of services to UNS customers. However, we believe it is reasonable, in this case, to allow $40,311 ($41,854 - $1,523), in accordance with RUCO's recommendation. As we indicated in the Southwest Gas Order, however, we expect UNS in its next rate case to provide more detailed support for the allowance of AGA dues and how the AGA's activities benefit the Company's customers aside from marketing and lobbying efforts.

Since my testimony in the last UNS Gas rate case, I have become aware of AGA dues disallowances made in gas utility rate cases in Michigan and California. In California, it appears that a disallowance of 25 percent of Pacific Gas and Electric Company's AGA dues was made by the Company itself in its filing in Application 05-12-002 (filed 12/2/05) as related to lobbying in the broader sense. In a more recent California rate case, Application No. 06-12-009, involving San Diego Gas and Electric, that utility appears to have proposed a 2 percent AGA dues disallowance for lobbying in the narrowest sense; the Division of Ratepayer Advocates ("DRA") proposed that the entire cost of SDG&E's AGA dues be excluded; and UCAN supported either the full disallowance or a 25 percent disallowance based on the result from the PG&E rate case and their review of AGA activities information.[11]

In a Michigan case involving Consumers Energy Company's gas utility operations[12], that utility conceded to a PSC Staff adjustment to disallow 16.17 percent of the AGA dues. As described in the testimony of MPSC Staff witness Wanda Clavon Jones[13]:

> Staff adjusted dues to eliminate activities that would not be allowed if the Company took on those activities for themselves. These activities include Public Affairs (15.43%) and Media Communication-Promotion (0.74%). Staff obtained the information necessary to make this adjustment from the Audit Report on Expenditures of the American Gas Association issued June 2001. The total disallowance is 16.17%, or $60,780. This disallowance is consistent with the last rate cases of Consumers, MichCon and MGU.

Q. How did you determine the percent disallowance for AGA dues?

A. This was based upon a review of information in the two most recent National Association of Utility Regulatory Commissioners (NARUC) sponsored Audit Reports of the

[11] A final order has apparently not been issued yet in the SDG&E rate case, and the parties are apparently working on a settlement.
[12] Michigan PSC Case No. U-13000.
[13] Filed 12/14/2001, at page 6

Expenditures of the American Gas Association, as well as the components by function of the AGA's 2007 and 2008 budgets. I also relied upon a Florida PSC Staff memorandum, discussed in more detail below, which contained a 40 percent AGA dues disallowance. Copies of relevant pages from the NARUC-sponsored audit reports are provided in Attachment RCS-4. AGA 2007 and 2008 budget information, by component, is summarized on Schedule C-6, page 2.

Q. What is the purpose of the NARUC-sponsored audits of AGA expenditures?

A. The purpose of the NARUC-sponsored audits of AGA expenditures is to provide regulatory commissions with information that is useful in helping them decide which, if any, of the costs of the association should be approved for inclusion in utility rates. As stated in the June 2001 memo to the Chairs and Chief Accountants of the State Regulatory Commissions included with the NARUC-sponsored audit of 1999 AGA expenditures: "Often, state commissioners review the costs of the association charged or allocated to the utilities in their jurisdiction in accordance with the policies of their commission for treatment of costs directly incurred by the state's utilities for similar activities." The NARUC-sponsored audit categorizes the AGA expenditures and, as stated in the aforementioned memo, "these expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit."

Q. Have other regulatory commissions required similar adjustments to utility-incurred AGA dues, based on the results of the NARUC-sponsored audits?

A. Yes. As an example, I have included in Attachment RCS-4, an excerpt from a Florida Public Service Commission Staff Memorandum (dated 12/23/03) in a City Gas Company rate case addressing this issue. As stated in that document:

In City Gas's last rate case, *In re: Request for rate increase by City Gas Company of Florida*, Docket No. 000768-GU, Order No. PSC-01-0316-PAA-GU, issued February 5, 2001, the Company removed $4,045 for AGA dues for lobbying. The Commission removed an additional combined amount of $4,970 for memberships, dues and contributions. *In re: Application for a rate increase by City Gas Company of Florida*, Docket No. 940276-GU, Order No. PSC-94-0957-FOF-GU, issued August 9, 1994, for interim purposes, the Commission disallowed 40% of AGA dues. This order stated that the percentage was based on the 1993 National Association of Regulatory Commission's (NARUC) Audit Report on the Expenditures of the American Gas Association (Audit Report). Order No. PSC-94-0957-FOF-GU further stated that this reduction was consistent with adjustments made in rate cases involving other gas companies. In the final order in Docket No. 940276-GU, Order No. PSC-94-1570-FOF-GU, issued December 19, 1994, the Commission removed 40.48% of AGA dues "which were related to lobbying and advertising that did not meet the criteria of being informational or educational in nature." In re: Request for rate increase by Florida Division of Chesapeake Utilities Corporation, Docket No. 000108-GU, Order No. PSC-00-2263-FOF-GU, issued November 28, 2000, the Commission removed 45.10% of AGA dues.

The latest NARUC Audit Report on AGA expenditures that Staff was able to locate is dated June, 2001, for the twelve-month period ended December 31, 1999. By a review of the Summary of Expenses, it appears that 41.65% of 1999 AGA expenditures are for lobbying and advertising. Staff has not been able to locate a more recent NARUC Audit Report of the AGA expenditures. However, because approximately 40% appears to have been consistent over a number of years, Staff believes it is not unreasonable to assume that 40% is representative of 2003 and 2004 expenditures and recommends that 40% of AGA dues be disallowed in this proceeding.

From information supplied by the Company, AGA dues were $39,277 in 2003. According to recommendations in Issue 44 and 45, Account 921 should be trended on inflation only at 2.0% for 2004. On that basis the 2004 amount is $40,063 ($39,277 x 1.02). Disallowing 40% would result in disallowing $16,025 for 2004. The Company's $2,847 adjustment reduces Staff's adjustment to $13,178 ($16,025 - $2,847) for 2004. This position follows past Commission practice of placing charitable contributions and advertising that is not informational or educational in nature below the line.

Based on the above analysis, Account 921, Office Supplies and Expenses, should be reduced by an additional $13,178 for AGA membership dues related to charitable contributions and advertising that is not informational or educational in nature.

The Company is in agreement with this adjustment.

Q. Did the Commission also address the issue of the appropriate portion of AGA dues to disallow for ratemaking purposes in the most recent Southwest Gas Corporation rate case?

A. Yes, it did. The Commission adopted a 40 percent disallowance of AGA dues in Decision No. 70665, in the recent Southwest Gas rate case. In Docket No. G-01551A-07-0504, the Commission adopted Staff's recommendation to disallow 40% of AGA dues. Decision No. 70665, at page 12 stated that:

> We find that Staff's recommended disallowance of 40 percent of AGA dues represents a reasonable approximation of the amount for which ratepayers receive no supportable benefit.

Q. What amount of AGA membership dues expense have you removed from test year expense?

A. As shown on Schedule C-6, I have removed 40 percent, or $18,678, from the $46,694 of test year expense for AGA membership dues. This removes $16,762 more than UNSG's proposed 4 percent removal which amounted to $1,915.

C-7 Outside Legal Expense

Q. Please explain RUCO's adjustment to Outside Legal Expense.

A. This adjustment removes a portion of UNS Gas' significant *pro forma* increase amount for normalizing outside legal expense in the test year.

Q. What is the test year amount of Outside Legal Expense?

A. The Company's test year expense for Outside Legal Expense (other than rate cases) is $83,555. The Company has made a *pro forma* adjustment to increase Outside Legal

Expense by $305,984 to normalize this expense in the test year, based on a three year average of 2005 - 2007 expenses, which included large annual legal costs related to an El Paso Natural Gas ("EPNG") pipeline case before the FERC.

Q. Describe UNS Gas' historical Outside Legal Expenses.

A. The Company spent $488,000, $439,000, and $242,000 in the years 2005, 2006, and 2007 on outside legal costs for matters other than ACC rate cases. A significant amount of these fees in those years are related to the EPNG regulatory proceedings before the FERC, which had settled. The Company's outside legal fees have steadily declined since its last rate case. The Company also stated in its UES Results of Operations for Year End 2008 :

Begin Confidential

[14] ***End Confidential***

Q. What amount of outside legal expense are you recommending?

A. I am recommending that a normalized amount of outside legal expense excluding the EPNG legal costs be used. Because it appears that some level of EPNG FERC costs will be ongoing, I have provided for an annual amount for EPNG FERC proceedings of approximately $100,000 based on actual test year costs. As shown on Schedule C-7, RUCO has reduced outside legal expense by $217,674.

C-8 Fleet Fuel Expense

Q. Please explain adjustment C-8.

[14] TF-6.46 UNSG(0571)07991

A. This adjustment reduces the Company's fleet fuel expense included in the test year. The test year fleet fuel expense is based on unusually high fuel prices in effect during the test year, in some months over $4.00 a gallon, the Country's record high point. The amount of gallons purchased in the test year is the highest among historical yearly gallons purchased. Schedule C-8 shows a historical comparison of gallons purchased by year. If one calculates a monthly average of gallons for 2009 and annualizes it for the rest of the 2009, the annual amount of gallons yields an amount lower than the three year average. The Company's response to RUCO data request 1.94 states the current price of gas as of May 6, 2009 is $2.09 per gallon. According to ArizonaGasPrices.com , the current price of gas in Arizona is $2.278 per gallon as of May 29, 2009, but has recently been trending higher. My adjustment to fleet fuel expense calculates fleet fuel expense based a three year average of gallons purchased multiplied by an the current price of gas as of May 29, 2009 of $2.278 per gallon. As shown on Schedule C-8, I have reduced fleet fuel expense by $240,913. This adjustment will be updated if gas prices change significantly during the course of this proceeding.

C-9 Rate Case Expense

Q. What amount of rate case expense is the Company requesting recovery for in this case?

A. UNS Gas is requesting recovery of $500,000 for current rate case expenses over three years for an annual allowance of $166,667 per year. The Company also included $100,000 of unamortized rate case expense from the prior rate case and proposed that also be normalized over three years for an additional amount of $33,333, bringing the Company's request for *pro forma* total rate case expense to $200,000 per year. The

Company stated in response to Staff data request TF 6.68 that it did not remove amortization of rate case expense related to the previous rate case that will be recovered prior to new rates becoming effective and therefore, the Company's test year amount of rate case expense included an additional $58,333. The response to TF 6.68 also states that this amount would be removed resulting in a reduction of test year rate case expense of $58,333.

Q. Do you agree with the Company's proposed amount of rate case expense for this case?

A. No. Even with the Company's proposed correction, the total amount of rate case expense is excessive and would represent an unreasonable burden on ratepayers. Additionally, the amount included in rates for an allowance for rate case expense should be understood to be a normalized amount, not an amortization.

Q. What total amount of rate case expense was allowed in the last UNSG rate case?

A. The allowance for rate case expense was based on a total amount of $300,000 for rate case expenses in its prior rate case, Docket No. G-04204A-06-0463, normalized over a period of three years.

Q. How does the current UNSG rate case compare with the last UNSG rate case?

A. The current UNS Gas rate case is similar to and presents many of the same issues and adjustments to rate base and operating expenses (i.e., CWIP, property taxes, incentive compensation, etc.), if not less, than those that were addressed by the

Commission in the Company's last rate case. For example, in the prior rate case, it was the Company's first case under its new ownership. The Company also conducted a depreciation study supporting new depreciation rates in the prior case. UNS Gas is not proposing to revise its depreciation rates in this case.

Q. What do you recommend for the allowance for rate case expense for UNS Gas in this proceeding?

A. I recommend an annual allowance of $100,000, based on normalizing a total amount of $300,000 over a three-year period. The $500,000 for current rate case cost requested by UNS Gas is nearly double (i.e., is almost 81 percent higher) the amount of rate case expense requested and allowed by the Commission in the Southwest Gas' last rate case, Docket No. G-01551A-07-0504, which was $276,000 in total and was normalized over a three-year period, to produce an annual allowance of $92,000 per year. The rate case expense allowance in the last UNS Gas case was $100,000, based on normalizing a total amount of $300,000 over three years. Additionally, the rate case allowance in the last UNS Electric rate case was $100,000, based on normalizing a total amount of $300,000 over three years. The current UNS Gas rate case has similarities to the last UNS Gas and UNS Electric rate cases in terms of both the scope of issues in the cases, and the majority of each application being sponsored by in-house or affiliated company staff.

Q. Please summarize your recommended adjustment.

A. I recommend an annual allowance of $100,000 per year, based on a total of $300,000 normalized over three years. Schedule C-9 reduces the Company's proposed annual allowance for current rate case costs by $100,000.

I also recommend that the amount recorded by UNS Gas in the test year of $58,333 for prior rate case expense be removed. The Company's response to Staff data request TF 6.68 indicates this adjustment is needed to correct an error in UNS Gas' filing.

As shown on Schedule C-9, my total adjustment allows for a $100,000 per year normalized rate case expense, and reduces the rate case expense in UNSG's filing by $158,333.

C-10 Interest Synchronization

Q. Please explain your interest synchronization adjustment.

A. The interest synchronization adjustment applies the weighted cost of debt to the calculation of test year income tax expense. After adjustments, my proposed rate base differs from that of the Company. This results in an adjustment to the amount of synchronized interest included in the tax calculation. The calculation of the interest synchronization adjustment is shown on Schedule C-10. This adjustment increases income tax expense by $30,215 - the amount shown on Schedule C-10 and decreases the Company' achieved operating income by a similar amount.

C-11 Property Tax Expense

Q. Please explain RUCO Adjustment C-11.

A. This adjustment reflects the most current average known property tax rate for the 2008 tax year.

Q. How did you determine the most current average known property tax rate for the 2008 tax year?

A. The Company's response to RUCO 1.90 indicates the most current average known property tax rate for the 2008 tax year is 7.6127 percent as opposed to the 8.1359 percent used by the Company in calculating test year property tax expense.

Q. How did you determine the recommended assessment rate?

A. As previously stated, Section 42-15001 of the Arizona State Legislature provides the current percentages for assessed valuation of class one property for the years 2005 through 2010. The new assessment rate schedule provides for decreasing the 25 percent rate applicable in 2005 by 0.5 for the year 2006 and 1.0 percent each year thereafter until a 20 percent rate is attained in 2011.

The assessment rate for 2008 was 23 percent. The Company's calculation used the 22 percent assessment rate for 2009. Since the Commission approved rates are expected to become effective no later December 1, 2009, and the Company's anticipated rate case interval is three years, as evidenced by the Company's and RUCO's proposed normalization period for rate case expense, the property tax rate that will be effect for 2009 should be used. In terms of determining the recommended assessment rate, I also considered how my recommendation in the current UNS Gas rate case compares with property tax rates approved in recent Arizona gas rate cases. This comparison is summarized in the following table:

Utility:	UNS Gas, Inc	Southwest Gas Corp.	UNS Gas, Inc	Southwest Gas Corp.
Docket:	G-04204A-08-0571	G-01551A-07-0504	G-04204A-06-0463	G-01551A-04-0876
Test Year Ended:	6/30/2008	4/30/2007	12/31/2005	8/31/2004
New Rates Effective:	12/1/2009	12/1/2008	mid-2007	Order issued 2/23/06
Estimated Filing Interval:	3 years	3 years	3 years	3 to 4 years
Assessment Rate Used:	22 percent	23 percent	24 percent	24.5 percent
Corresponding Effective Year	2009	2008	2007	2006

In the 2004 SWG rate case, it appears that the utility, Staff and RUCO all ultimately agreed on the appropriateness of using a 24.5 percent assessment rate effective for 2006 in conjunction with the test year in that case ending August 31, 2004. In the last UNS Gas rate case an assessment rate of 24 percent for 2007 was used for rates that became effective in mid-2007. In the most recent Southwest Gas rate case, an assessment rate of 23 percent was used effective for 2008 for rates that became effective on December 1, 2008. I believe the appropriateness of using the known 22 percent assessment rate for 2009 in the current UNS Gas rate case is supported by the comparison in the above table.

Q. What is RUCO's recommended property tax expense adjustment?

A. As shown on Schedule C-11, Staff's recommended adjustment reduces UNS Gas' proposed property tax expense by $230,913.

C-12 2010 Pay Increase

Q. Please explain your adjustment for a 2010 pay increase.

A. This adjustment is shown on Schedule C-12, and reduces UNSG's proposed expense for payroll by $225,740 and related payroll tax expense by $24,882 to remove a projected 2010 pay increase. The Company increased its end-of-test-year payroll for two rounds of pay increases: a 3 percent increase in 2009 and another 3 percent increase projected for 2010. The 2010 pay increase is not known and measurable, and is too far removed from the test year. Additionally, with the poor economy many companies are curtailing budgeted pay increases. For all of these reasons, the 2010 pay increase projected by UNS Gas should be removed from test year expense.

Q. Does this conclude your testimony?

A. Yes, it does.

Attachment RCS-1
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed was the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)

82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. - Partial and Immediate (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-7650	Consumers Power Company – Final (Michigan PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)
U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)

851007-WU	
& 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
R-860378	Duquesne Light Company Surrebuttal (Pennsylvania PUC)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities
T E-1032-88-102	Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)
R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona
& U-1551-89-103	Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and	Intrastate Access Charge Methodology, Pool and Rates
TC-91-040B	Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS &	General Development Utilities - Port Malabar and
911-67-WS	West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)

R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)
Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)

PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)
E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)

Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016,	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
Phase I	
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)
97-12-020	
Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)
Docket No. E-01345A-06-009	Arizona Public Service Company (Arizona Corporation Commission)
Case No. 05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power (West Virginia PSC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)

Case No. U-14347	Consumers Energy Company (Michigan PSC)
Case No. 05-725-EL-UNC	Cincinnati Gas & Electric Company (PUC of Ohio)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 19142-U	Georgia Power Company (Georgia PSC)
Docket No. 03-07-01RE01	Connecticut Light & Power Company (CT DPUC)
Docket No. 19042-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 2004-178-E	South Carolina Electric & Gas Company (South Carolina PSC)
Docket No. 03-07-02	Connecticut Light & Power Company (CT DPUC)
Docket No. EX02060363, Phases I&II	Rockland Electric Company (NJ BPU)
Docket No. U-00-88	ENSTAR Natural Gas Company and Alaska Pipeline Company (Regulatory Commission of Alaska)
Phase 1-2002 IERM, Docket No. 01-05-19 REO3	Yankee Gas Service (CT DPUC)
Docket No. G-01551A-00-0309	Southwest Gas Corporation (Arizona Corporation Commission)
Docket No. U-02-075	Interior Telephone Company, Inc. (Regulatory Commission of Alaska)
Docket No. 05-SCNT-1048-AUD	South Central Telephone Company (Kansas CC)
Docket No. 05-TRCT-607-KSF	Tri-County Telephone Company (Kansas CC)
Docket No. 05-KOKT-060-AUD	Kan Okla Telephone Company (Kansas CC)
Docket No. 2002-747	Northland Telephone Company of Maine (Maine PUC)
Docket No. 2003-34	Sidney Telephone Company (Maine PUC)
Docket No. 2003-35	Maine Telephone Company (Maine PUC)
Docket No. 2003-36	China Telephone Company (Maine PUC)
Docket No. 2003-37	Standish Telephone Company (Maine PUC)
Docket Nos. U-04-022, U-04-023	Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
Case 05-116-U/06-055-U	Entergy Arkansas, Inc. EFC (Arkansas Public Service Commission)
Case 04-137-U	Southwest Power Pool RTO (Arkansas Public Service Commission)
Case No. 7109/7160	Vermont Gas Systems (Department of Public Service)
Case No. ER-2006-0315	Empire District Electric Company (Missouri PSC)
Case No. ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
Docket No. U-05-043,44	Golden Heart Utilities/College Park Utilities (Regulatory Commission of Alaska)
A-122250F5000	Equitable Resources, Inc. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
E-01345A-05-0816	Arizona Public Service Company (Arizona CC)
Case No. U-14347	Consumers Energy Company (Michigan PSC)
E-01345A-06-009	Arizona Public Service Company (Arizona CC)
05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power Co. (West Virginia PSC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)
05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
U-06-45	Anchorage Water Utility (Regulatory Commission of Alaska)
03-93-EL-ATA, 06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)
Docket No. 2006-0386	Hawaiian Electric Company, Inc (Hawaii PUC)
E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)

G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
Docket No.UE-072300	Puget Sound Energy, Inc. (Washington UTC)
PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
A-2008-2063737	Babcock & Brown Infrastructure Fund North America, LP. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)

Attachment RCS-2

RUCO Accounting Schedules

Accompanying the Direct Testimony of Ralph C. Smith

UNS Gas Confidential Information Has Been Redacted

Schedule	Description	Pages	Note
	Revenue Requirement Summary Schedules		
A	Calculation of Revenue Deficiency (Sufficiency)	2	
A-1	Gross Revenue Conversion Factor	1	
B	Adjusted Rate Base	1	
B.1	Summary of Adjustments to Rate Base	1	
C	Adjusted Net Operating Income	1	
C.1	Summary of Net Operating Income Adjustments	2	
D	Capital Structure and Cost Rates	2	
	Rate Base Adjustments		
B-1	Construction Work in Progress/Post Test Year Plant	1	
B-2	Customer Advances	1	
B-3	Prepayments	1	
B-4	Cash Working Capital		[A]
B-5	Customer Deposits		[A]
B-5	Accumulated Deferred Income Taxes	1	
	Net Operating Income Adjustments		
C-1	Gas Retail Revenue	1	
C-2	Depreciation & Property Taxes for CWIP	2	
C-3	Incentive Compensation	1	
C-4	Stock-Based Compensation Expense	1	[B]
C-5	Supplemental Executive Retirement Plan Expense	1	
C-6	American Gas Association Dues	2	
C-7	Outside Services Legal Expense	1	
C-8	Fleet Fuel Expense	1	
C-8.1	Fleet Fuel Usage	1	
C-9	Rate Case Expense	1	
C-10	Interest Synchronization	1	
C-11	Property Tax Expense	1	
C-12	2010 Pay Increase	2	
	Total Pages (including Contents page)	31	

[A] Placeholder, schedule reserved for adjustment to be calculated at a later stage of proceeding, if necessary

[B] Contains Company-designated CONFIDENTIAL INFORMATION

UNS Gas Inc.
Computation of Increase in Gross Revenue Requirement

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule A
Page 1 of 2

			UNS Proposed		RUCO Proposed	
Line No.	Description	Reference	Original Cost (A)	Fair Value (B)	Original Cost (C)	Fair Value (D)
1	Adjusted Rate Base	Sch. B	$ 182,293,106	$ 255,779,939	$ 179,884,439	$ 252,877,851
2	Rate of Return	Sch D	9.54%	6.80%	7.55%	5.38%
3	Operating Income Required		$ 17,390,762	$ 17,390,762	$ 13,581,275	$ 13,604,828
4	Net Operating Income Available	Sch. C	$ 11,600,004	$ 11,600,004	$ 13,090,781	$ 13,090,781
5	Operating Income Excess/Deficiency		$ 5,790,758	$ 5,790,758	$ 490,494	$ 514,047
6	Gross Revenue Conversion Factor	Sch. A-1	1.6366	1.6366	1.636582	1.636582
7	Overall Revenue Requirement		$ 9,477,048	$ 9,477,048	$ 803,000	$ 841,000
8	Difference between OCRB and FVRB calculations			$ -		$ 38,000

Notes and Source
Cols. A & B taken from UNS Gas, Inc. filing, Schedule A-1

8	Gas Retail Revenue	Sch. C	$ 51,157,763	$ 51,157,763	$ 51,673,766	$ 51,673,766
9	Percentage Increase		18.53%	18.53%	1.55%	1.63%

See page 2 for additional Fair Value calculations RUCO is presenting for the Commission's consideration.
RUCO's amounts on line 7 are rounded to the nearest thousand.

UNS Gas Inc.
Computation of Increase in Gross Revenue Requirement

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule A

Line No.	Description	Reference	Fair Value Calculation 1 (A)	Fair Value Calculation 2 (B)	Fair Value Calculation 3 (C)	Fair Value Calculation 4 (D)	RUCO Recommended (E)
1	Adjusted Rate Base	Sch. B	$ 252,877,851	$ 252,877,851	$ 252,877,851	$ 252,877,851	$ 252,877,851
2	Rate of Return	Sch D	6.30%	5.05%	5.37%	5.73%	5.38% [a]
3	Operating Income Required		$ 15,931,305	$ 12,770,331	$ 13,579,541	$ 14,489,901	$ 13,604,828
4	Net Operating Income Available	Sch. C	$ 13,090,781	$ 13,090,781	$ 13,090,781	$ 13,090,781	$ 13,090,781
5	Operating Income Excess/Deficiency		$ 2,840,524	$ (320,450)	$ 488,760	$ 1,399,120	$ 514,047
6	Gross Revenue Conversion Factor	Sch. A-1	1.636582	1.636582	1.636582	1.636582	1.636582
7	Overall Revenue Requiremen		$ 4,649,000	$ (524,000)	$ 800,000	$ 2,290,000	$ 841,000 [b]
		Evaluation:	way too high	too low	too low	too high	recommendation

Notes and Source

8	Gas Retail Revenue	Sch. C	$ 51,673,766	$ 51,673,766	$ 51,673,766	$ 51,673,766	$ 51,673,766
9	Percentage Increase		9.00%	-1.01%	1.55%	4.43%	1.63%

RUCO's amounts on line 7 are rounded to the nearest thousand.

Explanation of Fair Value Calcualtions (See Schedule D, page 2, for details):

Calculation 1 - Reduce Recommended OCRB-Based Return on Equity for Estimated Inflation
Calculation 2 - Reduce Recommended OCRB-Based Overall Rate of Return for Estimated Inflation
Calculation 3 - With Fair Value Rate Base Increment at Zero Cost
Calculation 4 - With Fair Value Rate Base Increment at 1.25 Percent

[a] Recommended FVROR selected based on informed judgment after reviewing OCRB and FVRB calculations
[b] See page 1 of this schedule for how this recommendation compares with an OCRB-based calculation

UNS Gas, Inc.
Computation of Gross Revenue Conversion Factor

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule A-1

Line No.	Description	Company Proposed (A)	RUCO Proposed (B)
1	Gross Revenue	100.00%	100.00000%
2	Less: Uncollectible Revenue	0.487000%	0.48700%
3	Taxable Income as a Percent	99.51%	99.51300%
4	Less: Federal and State Income Taxes	38.41%	38.41003%
5	Change in Net Operating Income	61.10%	61.10297%
6	Gross Revenue Conversion Factor	1.6366	1.636582

Notes and Source

Col.A: UNS Gas Inc. Filing, Schedule C-3

7	Combined Income Tax Rate		38.5980%

UNS Gas, Inc.
Original Cost and RCND Adjusted Rate Base

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule B
Page 1 of 1

Line No.	Description	Original Cost: As Adjusted by UNS (A)	Original Cost: RUCO Adjustments (B)	Original Cost: As Adjusted by RUCO (C)	RCND: As Adjusted by UNS (D)	RCND: RUCO Adjustments (E)	RCND: As Adjusted by RUCO (F)
1	Gross Utility Plant in Service	$ 318,227,624	$ (1,527,588)	$ 316,700,036	$ 561,025,858	$ (2,514,427)	$ 558,511,431
2	Less: Accumulated Depreciation	$ (87,543,544)	$ -	$ (87,543,544)	$ (152,278,962)	$ -	$ (152,278,962)
3	Net Utility Plant in Service	$ 230,684,080	$ (1,527,588)	$ 229,156,492	$ 408,746,896	$ (2,514,427)	$ 406,232,469
4	Southern Union Acquisition Premium	$ -	$ -	$ -	$ -	$ -	$ -
5	Less: Accum. Amort. - So. Union Acq. Premium	$ -	$ -	$ -	$ (3,553)	$ -	$ (3,553)
6	Net Southern Union Acquisition Premium	$ -		$ -	$ (3,553)	$ -	$ (3,553)
7	Citizens Acquisition Discount	$ (30,709,738)	$ -	$ (30,709,738)	$ (55,126,579)	$ -	$ (55,126,579)
8	Less: Accum. Amort. - Citizens Acq. Discount	$ (3,935,647)	$ -	$ (3,935,647)	$ (6,658,438)	$ -	$ (6,658,438)
9	Net Citizens Acquisition Discount	$ (26,774,091)	$ -	$ (26,774,091)	$ (48,468,141)	$ -	$ (48,468,141)
10	Total Net Utility Plant	$ 203,909,989	$ (1,527,588)	$ 202,382,401	$ 360,275,202	$ (2,514,427)	$ 357,760,775
11	Customer Advances for Construction	$ (11,235,876)	$ (589,152)	$ (11,825,028)	$ (12,759,773)	$ (589,152)	$ (13,348,925)
							$ -
12	Customer Deposits	$ (2,609,271)	$ -	$ (2,609,271)	$ (2,609,271)	$ -	$ (2,609,271)
							$ -
13	Accumulated Deferred Income Taxes	$ (10,606,875)	$ (196,256)	$ (10,803,131)	$ (18,474,527)	$ (196,256)	$ (18,670,783)
14	Total Deductions	$ (24,452,022)	$ (785,408)	$ (25,237,430)	$ (33,843,571)	$ (785,408)	$ (34,628,979)
15	Allowance for Working Capital	$ 2,364,921	$ (95,671)	$ 2,269,250	$ 2,364,921	$ (95,671)	$ 2,269,250
							$ -
16	Regulatory Assets	$ 492,590	$ -	$ 492,590	$ 492,590	$ -	$ 492,590
							$ -
17	Regulatory Liabilities	$ (22,372)	$ -	$ (22,372)	$ (22,372)	$ -	$ (22,372)
18	Total Rate Base	$ 182,293,106	$ (2,408,667)	$ 179,884,439	$ 329,266,770	$ (3,395,506)	$ 325,871,264

Notes and Source
Cols. A and D: UNS Gas Inc. filing, Schedule B-1

Line No.	Fair Value Calculation (Per Company)		
19	Original Cost	$ 182,293,106	
20	RCND	$ 329,266,770	
21	Total	$ 511,559,876	
22	Average (Fair Value)	$ 255,779,939	See Sch. A

Line No.	Fair Value Calculation (Per RUCO)		
23	Original Cost	$ 179,884,439	
24	RCND	$ 325,871,264	
25	Total	$ 505,755,703	
26	Average (Fair Value)	$ 252,877,851	See Sch. A

UNS Gas, Inc.
Summary of Rate Base Adjustments

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule B.1
Page 1 of 1

Line No.	Description	RUCO Adjustments	Construction Work in Progress/Post Test Year Plant B-1	Customer Advances B-2	Prepayments B-3	Cash Working Capital B-4	Customer Deposits B-5	Accumulated Deferred Income Taxes B-6
1	Gross Utility Plant in Service	$ (1,527,588)	$ (1,527,588)					
2	Less: Accumulated Depreciation	$ -						
3	Net Utility Plant in Service	$ (1,527,588)	$ (1,527,588)	$ -	$ -	$ -	$ -	$ -
4	Southern Union Acquisition Premium	$ -						
5	Less: Accum. Amort. - So. Union Acq. Premium	$ -						
6	Net Southern Union Acquisition Premium	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Citizens Acquisition Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Less: Accum. Amort. - Citizens Acq. Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Net Citizens Acquisition Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Total Net Utility Plant	$ (1,527,588)	$ (1,527,588)	$ -	$ -	$ -	$ -	$ -
11	Customer Advances for Construction	$ (589,152)		$ (589,152)				
12	Customer Deposits	$ -						
13	Accumulated Deferred Income Taxes	$ (196,256)						$ (196,256)
14	Total Deductions	$ (785,408)	$ -	$ (589,152)	$ -	$ -	$ -	$ (196,256)
15	Allowance for Working Capital	$ (95,671)			$ (95,671)			
16	Regulatory Assets	$ -						
17	Regulatory Liabilities	$ -						
18	Total Rate Base	$ (2,408,667)	$ (1,527,588)	$ (589,152)	$ (95,671)	$ -	$ -	$ (196,256)

UNS Gas, Inc.
Adjusted Net Operating Income

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule C
Page 1 of 1

Line No.	Description	As Adjusted by UNS (A)	RUCO Adjustments (B)	As Adjusted by RUCO (C)
	Operating Revenues			
1	Gas Retail Revenues	$ 51,157,763	$ 516,003	$ 51,673,766
2	Other Operating Revenues	$ 1,744,743	$ -	$ 1,744,743
3	Total Operating Revenues	$ 52,902,506	$ 516,003	$ 53,418,509
	Operating Expenses			
4	Purchased Gas	$ 397,635	$ -	$ 397,635
5	Other O&M Expenses	$ 24,719,113	$ (1,378,677)	$ 23,340,436
6	Depreciation & Amortization	$ 8,240,005	$ (58,107)	$ 8,181,898
7	Taxes Other Than Income Taxes	$ 4,342,078	$ (524,318)	$ 3,817,760
8	Income Taxes	$ 3,603,671	$ 986,328	$ 4,589,999
9	Total Operating Expenses	$ 41,302,502	$ (974,774)	$ 40,327,728
10	Net Operating Income	$ 11,600,004	$ 1,490,777	$ 13,090,781

Notes and Source
Col. A: UNS Gas Inc. filing, Schedule C-1
Col. B: Staff Schedule C.1

UNS Gas, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule C.1

Line No.	Description	RUCO Adjustments	Gas Retail Revenue	Depreciation & Property Taxes for CWIP	Incentive Compensation	Stock-Based Compensation Expense	Supplemental Executive Retirement Plan Expense	American Gas Association Dues
			C-1	C-2	C-3	C-4	C-5	C-6
	Operating Revenues							
1	Gas Retail Revenues	$ 516,003	$ 516,003					
2	Other Operating Revenues	$ -						
3	Total Operating Revenues	$ 516,003	$ 516,003	$ -	$ -	$ -	$ -	
	Operating Expenses							
4	Purchased Gas	$ -						
5	Other O&M Expenses	$ (1,378,677)		$ (11,351)	$ (140,484)	$ (266,399)	$ (101,021)	$ (16,762)
6	Depreciation & Amortization	$ (58,107)		$ (58,107)				
7	Taxes Other Than Income Taxes	$ (524,318)		$ (25,584)	$ (12,027)			
9	PRE-TAX OPERATING EXPENSES	$ (1,961,102)	$ -	$ (95,042)	$ (152,511)	$ (266,399)	$ (101,021)	$ (16,762)
10	PRE-TAX OPERATING INCOME	$ 2,477,105	$ 516,003	$ 95,042	$ 152,511	$ 266,399	$ 101,021	$ 16,762
11	Income Taxes	$ 986,328	$ 199,167	$ 36,684	$ 58,866	$ 102,825	$ 38,992	$ 6,470
11	TOTAL OPERATING EXPENSES	$ (974,774)	$ 199,167	$ (58,358)	$ (93,645)	$ (163,574)	$ (62,029)	$ (10,292)
12	OPERATING INCOME	$ 1,490,777	$ 316,836	$ 58,358	$ 93,645	$ 163,574	$ 62,029	$ 10,292

Notes and Source

Combined Effective Tax Rate 38.5980%

UNS Gas, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule C.1

Line No.	Description	Outside Services Legal Expense	Fleet Fuel Expense	Rate Case Expense	Interest Synchronization	Property Tax Expense	2010 Pay Increase
		C-7	C-8	C-9	C-10	C-11	C-12
	Operating Revenues						
1	Gas Retail Revenues						
2	Other Operating Revenues						
3	Total Operating Revenues		$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
4	Purchased Gas						
5	Other O&M Expenses	$ (217,674)	$ (240,913)	$ (158,333)			$ (225,740)
6	Depreciation & Amortization						
7	Taxes Other Than Income Taxes		$ (230,913)			$ (230,913)	$ (24,881)
9	PRE-TAX OPERATING EXPENSES	$ (217,674)	$ (471,826)	$ (158,333)	$ -	$ (230,913)	$ (250,621)
10	PRE-TAX OPERATING INCOME	$ 217,674	$ 471,826	$ 158,333	$ -	$ 230,913	$ 250,621
11	Income Taxes	$ 84,018	$ 182,115	$ 61,113	$ 30,215	$ 89,128	$ 96,735
11	TOTAL OPERATING EXPENSES	$ (133,656)	$ (289,711)	$ (97,220)	$ 30,215	$ (141,785)	$ (153,886)
12	OPERATING INCOME	$ 133,656	$ 289,711	$ 97,220	$ (30,215)	$ 141,785	$ 153,886

Notes and Source

Combined Effective Tax Rate 38.5980%

UNS Gas, Inc.
Capital Structure & Cost Rates

Test Year Ended June 30, 2008

Line No.	Capital Source	Capitalization Amount (A)	Capitalization Percent (B)	Cost Rate (C)	Weighted Avg. Cost of Capital (D)
	I. UNS Gas - Proposed				
1	Short-Term Debt	n/a	n/a	3.95%	n/a
2	Long-Term Debt	$ 99,265	50.01%	6.49%	3.25%
3	Common Stock Equity	$ 99,242	49.99%	11.00%	5.50%
4	Total Capital	$ 198,507	100.00%		8.75%
5	Fair Value Adjustment				0.79%
6	UNS Gas Proposed Return				9.54%
	II. UNS Gas Proposed to Show Equivalent Requested ROE				
7	Short-Term Debt	$ -	0.00%	3.95%	n/a
8	Long-Term Debt	$ 99,265	50.01%	6.49%	3.25%
9	Common Stock Equity	$ 99,242	49.99%	**12.58%**	6.29%
10	Total Capital	$ 198,507	100.00%		9.54%
	III. RUCO - Proposed Rate of Return for Original Cost Rate Base				
11	Short-Term Debt	n/a	n/a	3.95%	n/a
12	Long-Term Debt	$ 99,265	50.01%	6.49%	3.25%
13	Common Stock Equity	$ 99,242	49.99%	8.61%	4.30%
14	Total Capital	$ 198,507	100.00%		7.55%
15	Difference				-1.99%
16	Weighted Cost of Debt				3.25%

Notes and Source
Lines 1-4 taken from UNS Gas Inc. filing, Schedule D-1
Lines 5&6: UNS Gas filing, Schedule A
Lines 11-14: RUCO witness William Rigsby

UNS Gas, Inc.
Capital Structure & Cost Rates

Docket No. G-04204A-08-0571
Schedule D
Page 2 of 2

Test Year Ended June 30, 2008

Line No.	Capital Source	Capitalization Amount	Capitalization Percent	Cost Rate	Weighted Avg. Cost of Capital
		(A)	(B)	(C)	(D)
	Calculation 1 - Reduce Recommended OCRB-Based Return on Equity for Estimated Inflation				
1	Short-Term Debt	n/a	n/a	3.95%	n/a
2	Long-Term Debt	$ 99,265	50.01%	6.49%	3.25%
3	Common Stock Equity	$ 99,242	49.99%	6.11% [a]	3.05%
4	Total Capital	$ 198,507	100.00%		6.30%
	Calculation 2 - Reduce Recommended OCRB-Based Overall Rate of Return for Estimated Inflation				
5	Short-Term Debt	$ -	0.00%	3.95%	n/a
6	Long-Term Debt	$ 99,265	50.01%	6.49%	3.25%
7	Common Stock Equity	$ 99,242	49.99%	8.61%	4.30%
8	Total Capital	$ 198,507	100.00%		7.55%
9	Fair Value Adjustment				-2.50% [b]
10	UNS Gas Proposed Return				5.05%
	Calculation 3 - With Fair Value Rate Base Increment at Zero Cost				
11	Short-Term Debt	$ -	0.00%	3.95%	0.00%
12	Long-Term Debt	$ 89,952,641	35.57%	6.49%	2.31%
13	Common Stock Equity	$ 89,931,798	35.56%	8.61%	3.06%
14	Capital financing OCRB	$ 179,884,439			
15	Appreciation above OCRB not recognized on utility's books	$ 72,993,413	28.87%	0% [c]	0.00%
16	Total capital supporting FVRB	$ 252,877,852	100.00%		5.37%
	Calculation 4 - With Fair Value Rate Base Increment at 1.25 Percent				
17	Short-Term Debt	$ -	0.00%	3.95%	0.00%
18	Long-Term Debt	$ 89,952,641	35.57%	6.49%	2.31%
19	Common Stock Equity	$ 89,931,798	35.56%	8.61%	3.06%
20	Capital financing OCRB	$ 179,884,439			
21	Appreciation above OCRB not recognized on utility's books	$ 72,993,413	28.87%	1.25% [d]	0.36%
22	Total capital supporting FVRB	$ 252,877,852	100.00%		5.73%

Notes and Source

[a] Per RUCO witness William Rigsby, inflation to remove from OCRB-based ROE: -2.50%

[b] Per RUCO witness Rigsby, inflation to remove from OCRB-based Overall Rate of Return: -2.50%

[c] The appreciation of Fair Value over Original Cost has not been recognized on the utility's books. Such off-book appreciation has not been financed by debt or equity capital recorded on the utility's books. The appreciation over Original Cost book value is therefore recognized for cost of capital purposes at zero cost.

[d] Approximates the mid-point of a range from zero to 2.5 percent, with 2.5 percent representing an approximate real risk-free rate of return

Lines 11-22, Col.A:

Fair Value Rate Base	$ 252,877,851	Schedule A
Original Cost Rate Base	$ 179,884,439	Schedule A
Difference	$ 72,993,413	

Difference is appreciation of Fair Value over Original Cost that is not recognized on the utility's books.

UNS Gas, Inc.
Construction Work in Progress/Post Test Year Plant

Test Year Ended June 30, 2008

Line No.	Description	Amount	Reference
1	Remove Construction Work in Progress	$ (1,527,588)	A&B

Notes and Source
A: UNS Gas Filing, Schedule B-2, page 2, line 1
B: Testimony of RUCO witness Ralph Smith

UNS Gas, Inc.
Customer Advances

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule B-2

Line No.	Description	Amount	Reference
1	Use Test Year End Balance	$ (589,152)	A&B

Notes and Source

A: UNS Gas Filing, Schedule B-2, page 3, Line 11
B: Testimony of RUCO witness Ralph Smith

UNS Gas, Inc.
Prepayments

Test Year Ended June 30, 2008

Line No.	Description	Amount	Reference
1	Use Test Year End Balance	$ (95,671)	A&B

Notes and Source

A: UNS Gas Filing, Schedule B-5, page 2, line 3
B: Testimony of RUCO witness Ralph Smith

UNS Gas, Inc.
Accumulated Deferred Income Taxes

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule B-6
Page 1 of 1

Line No.	Description	Per UNS Gas (A)	Per RUCO (B)	Adjustment (C)
	Account 190			
1	CIAC	$ 2,436,909	$ 2,436,909	$ -
2	Customer Advances	$ 4,402,955	$ 4,402,955	$ -
3	Customer Advances - CWIP	$ (227,413)		$ 227,413
4	Dividend Equivalents	$ 17,952		$ (17,952)
5	Restricted Stock	$ 24,316		$ (24,316)
6	Restricted Stock - Directors	$ 55,281		$ (55,281)
7	Stock Options	$ 155,708		$ (155,708)
8	Vacation	$ 169,367		$ (169,367)
9	Total Account 190	$ 7,035,076	$ 6,839,864	$ (195,211)
	Account 282			
10	Net Plant ADIT	$ (17,452,856)	$ (17,452,856)	$ -
	Account 283			
11	CARES Reg Asset	$ (190,140)	$ (190,140)	$ -
12	Pension	$ 1,045		$ (1,045)
13	Total Account 283	$ (189,095)	$ (190,140)	$ (1,045)
14	**Net ADIT**	$ (10,606,875)	$ (10,803,131)	$ (196,256)

Notes and Source
A: UNS Gas workpaper UNSG0571/02839
B: Testimony of RUCO witness Ralph Smith

UNS Gas, Inc.
Adjustment to Annualize Gas Retail Revenue

Docket No. G-04204A-08-0571
Schedule C-1
Page 1 of 1

Test)rmation Has Been Redacted**

Line No.	Description	Amount	Reference
1	UNS Gas Adjustment to Annualize Gas Retail Revenue	$ (516,003)	A
2	RUCO Recommended Adjustment to Annualized Gas Retail Revenue	$ -	B
3	Adjustment to Annualize Gas Retail Revenue	$ 516,003	L2 - L1

Notes and Source
A: UNS Gas Filing, Schedule C-2, page 1, line 1
B: See testimony

FERC 480/481/482

UNS Gas, Inc.
Remove Depreciation & Property Taxes for CWIP

Test Year Ended June 30, 2008

Line No.	Description	Account	Amount	Reference
1	CWIP Related Depreciation Expense	403	$ (58,107)	See page 2
2	Transportation Equip Depreciaton Charged to O&M	various	$ (11,351)	See page 2
3	CWIP Related Property Taxes	408	$ (25,584)	A
4	Total Adjustments		$ (95,042)	

Notes and Source

A: Testimony of RUCO witness Ralph Smith

5	CWIP included in Plant in Service Full Cash Value	$ (1,527,588)	Schedule B-1
6	Assessment Ratio	22.0%	Schedule C-11
7	Taxable Value	$ (336,069)	
8	Average Tax Rate	7.6127%	Schedule C-11
9	Property Tax	$ (25,584)	

UNS Gas, Inc.
Depreciation Related to Post Test Year Plant in Service

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule C-2
Page 2 of 2

Line No.	Description	FERC Acct	Adjustment (A)	Depreciation Rate (B)	Depreciation Expense (C)
	I. Adjustment to Depreciation Expense				
1	Mains - Replacements & Public Improvements	376	$ (817,127)	2.07%	$ (16,915)
2	Services - Replacements	380	$ (271,433)	2.82%	$ (7,654)
3	Structures and Improvements	390	$ (39,408)	4.89%	$ (1,927)
4	Office Furniture	391	$ (12,493)	4.55%	$ (568)
5	Office Furniture	391	$ (5,548)	20.00%	$ (1,110)
6	Transportation Equipment Class 1	392	$ (10,744)	14.71%	$ (1,580)
7	Transportation Equipment Class 2	392	$ (34,232)	17.87%	$ (6,117)
8	Transportation Equipment Class 3	392	$ (17,568)	22.68%	$ (3,984)
9	Transportation Equipment Class 4	392	$ (15,608)	13.04%	$ (2,035)
10	Transportation Equipment Class 5	392	$ (14,770)	11.83%	$ (1,747)
11	Tools & Shop Equipment	394	$ (9,431)	4.00%	$ (377)
12	Laboratory Equipment	395	$ (186,174)	11.11%	$ (20,684)
13	Power Operated Equipment	396	$ (69,759)	10.49%	$ (7,318)
14	Communication Equipment	397	$ (23,293)	6.67%	$ (1,554)
15	TOTAL		$ (1,527,589)		$ (73,571)
16	Less Transportation Equipment		$ 92,922		$ 15,465
17	Plant Adjustment Other than Transportation Equipment		$ (1,434,667)		
18	Depreciation Expense Adjustment				$ (58,107)
	II. Adjustment to O&M Expense for Depreciation on Transportation Equipment				
19	Depreciation on Transportation Equipment	Line 16			$ (15,465)
20	Transportation Equipment Charged to O&M				73.40%
21	Adjustment to O&M Expense				$ (11,351)

Source:
Company Depreciation Workpaper UNSG0571/02244 and related Excel file

UNS Gas, Inc.
Incentive Compensation

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule C-3

Line No.	Description	Amount	Reference
1	Adjustment to Incentive Compensation Expense	$ (140,484)	A
2	Adjustment to Taxes Other Than Income	$ (12,027)	A

Notes and Source

A: Per Company's workpapers showing calculation of Incentive Compensation adjustment (except where noted)

FERC Acct	FERC Account Description	Company Amount	Disallowance Percentage	RUCO Adjusted Amount
870	Transportation Operation Supervision and Engineering	$ 26,217	50%	$ (13,109)
874	Distribution - Mains & Services Expense	$ 48,980	50%	$ (24,490)
878	Distribution - Meter Expense	$ -	50%	$ -
880	Distribution Other Expenses	$ 31,315	50%	$ (15,658)
887	Distribution - Maintenance of Mains	$ 35,188	50%	$ (17,594)
903	Customer Records/Collections Expense	$ -	50%	$ -
920	Administrative & General Salaries	$ 139,268	50%	$ (69,634)
		$ 280,968		$ (140,484)
408	Taxes Other Than Income Taxes	$ 24,054	50%	$ (12,027)

UNS Gas, Inc.
Stock-Based Compensation Expense

Test Year Ended June 30, 2008

Line No.	Description	Amount	Reference
1	Stock Based Compensation Expense	$ (266,399)	A
2	Adjustment to Taxes Other Than Income	N/A	B

Notes and Source

A Supplemental Response to RUCO 1.46

FERC Acct	Description	Company Amount	Disallowance Percentage	RUCO Adjustment Amount
	BEGIN UNSG CONFIDENTIAL			
	END UNSG CONFIDENTIAL			
	Total	$ 266,399		$ (266,399)

UNS Gas, Inc.
Supplemental Executive Retirement Plan Expense

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule C-5

Line No.	Description	Amount	Reference
1	Supplemental Executive Retirement Plan Expense	$ (101,021)	A

Notes and Source

A Response to Staff data request TF 6.64

FERC Account 926

UNS Gas, Inc.
American Gas Association Dues

Test Year Ended June 30, 2008

Line No.	Description	RUCO Adjustment (A)	Company Adjustment (B)	Net RUCO Adjustment (C)	Reference
1	Test Year AGA Dues Per Filing	$ 46,694	$ 46,694		A
2	Recommended AGA Dues	$ 28,016	$ 44,779		B
3	Recommended disallowance	$ (18,678)	$ (1,915)	$ (16,762)	C

Notes and Source

A: Response to TF 6.54, UNS Gas Workpaper UNSG0571/02500, RUCO 1.48

2007 Invoice	$ 45,508	50%	$ 22,754
2008 Invoice	$ 47,879	50%	$ 23,940
			$ 46,694

B:

	Per RUCO	Per UNS Gas
2007 AGA Dues Per Filing	$ 46,694	$ 46,694
Recommended disallowance	$ (18,678)	$ (1,915)
Recommended AGA Dues	$ 28,016	$ 44,779

C:

	Per RUCO	Per UNS Gas	
2007 AGA Dues Per Filing	$ 46,694	$ 47,879	
Recommended disallowance %	40% D	4%	
Recommended disallowance	$ (18,678)	$ (1,915)	$ (16,762)

D: See testimony and page 2 of this schedule

UNS Gas, Inc.
American Gas Association
Schedule of Expenses by NARUC Category

		March 2005 NARUC Audit Report for Year Ended 12/31/02		AGA 2007 Budget			AGA 2008 Budget		
Line No.	NARUC Operating Expense Category	% of Dues	Recommended Disallowance	% of Dues	With G&A Allocated	Recommended Disallowance	% of Dues	With G&A Allocated	Recommended Disallowance
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	Public Affairs	24.13%	24.13%	23.29%	28.67%	28.67%	24.44%	30.63%	30.63%
2	Advertising			1.39%	1.71%	1.71%	1.18%	1.48%	1.48%
3	Communications	15.53%							
4	Corporate Affairs and International	10.54%	10.54%	8.44%	10.39%	10.39%	9.14%	11.46%	11.46%
5	General Counsel & Corp Secretary	5.20%	2.60%	4.09%	5.04%	2.52%	4.17%	5.23%	2.62%
6	Regulatory Affairs	15.51%							
7	Policy Planning & Regulatory Affairs			14.76%	18.17%		15.78%	19.78%	
8	Marketing Department	2.37%	2.37%						
9	Operating & Engineering Services	15.85%		24.11%	29.68%		21.71%	27.21%	
10	Policy & Analysis	12.94%							
11	Industry Finance & Admin. Programs	4.75%		5.16%	6.35%		3.36%	4.21%	
12	General & Administrative			18.77%			20.22%		
13	Total Expenses	106.82%	39.64%	100.01%	100.01%	43.29%	100.00%	100.00%	46.19%
14	Lobbying per IRC Section 162			2%			4%		

Notes and Source

Col.A: March 2005 Annual Audit Report on the Expenditures of the American Gas Association for the 12 month period ended December 31, 2002
Col.C: From Docket No. G-01551A-07-0504, Southwest Gas' Response to Staff data request STF-6-52; also see UNSG0571/07347
Col.F: From Docket No. G-01551A-07-0504, Southwest Gas' Response to Staff data request STF-6-50(b); also see UNSG0571/07348

UNS Gas, Inc.
Outside Services Legal Expense

Test Year Ended June 30, 2008

Line No.	Description	Amount	Reference
1	UNS Gas Request for Non-Rate Case Legal Expense	$ 389,539	A
2	RUCO recommendation	$ 171,865	B
3	Adjustment to Outside Services Legal Expense	$ (217,674)	

Notes and Source

A	UNS Gas Workpapers including UNSG0571/02563 - 02574		
B	Amount of past El Paso Gas legal expense included in UNS Gas' request:		
4	2005	$ 361,233	
5	2006	$ 395,247	
6	2007	$ 196,203	
7	Total	$ 952,683	
8	Three-Year Average	$ 317,561	
9	Test Year Amount	$ 99,887	
10	Company request for past El Paso Gas legal expense over test year actual	$ 217,674	
11	Company Normalized Amount without past El Paso Gas Legal Cost	$ 71,978	
12	Increase over Test Year Actual for Past El Paso Gas Legal Expense	$ 217,674	
13	Test Year Actual without Legal Expense for 2006 Rate Case	$ 83,555	
14	Amount over Test Year to Normalize other legal costs (not El Paso Gas)	$ 88,310	
15	Recommended normalized level	$ 171,865	

FERC Account 923

UNS Gas, Inc.
Fleet Fuel Expense

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule C-8

Line No.	Description		Amount	Reference
1	UNS Gas Adjustment to Fleet Fuel Expense	$	732,092	A
2	RUCO Recommended Fleet Fuel Expense	$	491,179	B
3	Adjustment to Fleet Fuel Expense	$	(240,913)	L2 - L1

Notes and Source

A RUCO 1.94

2006		214,935	Sch C-8.1
2007		218,847	Sch C-8.1
2008		213,074	Sch C-8.1
3 Yr Avg		215,619	
Price of fuel	$	2.278	B
Normalized fuel expense	$	491,179	

B ArizonaGasPrices.com

UNS Gas, Inc.
Fleet Fuel Expense

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule C-8.1

	Gallons			
Month	**2006**	**2007**	**2008**	**2009**
Jan	20,562	18,777	22,234	21,061
Feb	16,694	16,937	18,597	16,214
Mar	18,731	19,618	18,173	17,150
Apr	17,743	17,833	18,840	17,187
May	19,073	18,946	18,942	
Jun	18,290	18,310	14,687	
Jul	18,709	20,070	18,641	
Aug	19,698	19,460	17,712	
Sep	18,828	17,468	17,924	
Oct	17,542	18,625	18,345	
Nov	16,567	17,086	15,368	
Dec	12,498	15,717	13,611	
Total	214,935	218,847	213,074	71,612

Source:
RUCO 1.94

UNS Gas, Inc.
Rate Case Expense

Test Year Ended June 30, 2008

Line No.	Description	Amount	Reference
	I. Normalized Allowance for Rate Case Cost		
1	UNS Gas Rate Case Expense per Company Filing	$ 200,000	A
2	RUCO Recommended Rate Case Expense	$ 100,000	B
3	Adjustment for Normalized Rate Case Expense Allowance	$ (100,000)	L.2 - L.1
	II. Remove Prior Rate Case Cost from Test Year		
4	Remove Prior Rate Case Cost from Test Year	$ (58,333)	C
	III. Total Adjustment to UNS Gas' Proposed Rate Case Expense		
5	Total Adjustment to UNS Gas' Proposed Rate Case Expense	$ (158,333)	L.3 + L.4

Notes and Source

A: UNS Gas filing, Schedule C-2, page 3, line 5

B: RUCO Recommended Annual Allowance for NormalizedRate Case Expense

6	Recommended Total Allowance for Current Rate Case	$ 300,000
7	Normalized Over Three Years	3
8	Normalized Annual Allowance for Rate Case Expense	$ 100,000

C: Response to Staff data request TF 6.68

UNS Gas, Inc.
Interest Synchronization

Test Year Ended June 30, 2008

Docket No. G-04204A-06-0463
Schedule C-10

Line No.	Description		Amount	Reference
1	Adjusted rate base	$	179,884,439	Schedule B
2	Weighted cost of debt		3.25%	Schedule D
3	Synchronized interest deduction	$	5,846,244	Line 1 x Line 2
4	Synchronized interest deduction per UNS Gas	$	5,924,526	Note A
5	Difference (decreased) increased interest deduction	$	(78,282)	Line 3 - Line 4
6	Combined federal and state income tax rates		38.598%	B
7	Increase (decrease) to income tax expense	$	30,215	

Notes and Source

A UNS Gas filing, Schedule B-5, page 3 of 3, line 18

B Schedule A-1

UNS Gas, Inc.
Property Tax Expense

Docket No. G-04204A-08-0571
Schedule C-11
Page 1 of 1

Test Year Ended June 30, 2008

Line No.	Description		Amount	Reference
1	UNS Gas Proposed Increase to Property Tax Expense	$	1,354,074	A
2	RUCO Proposed Increase to Property Tax Expense	$	1,123,161	B
3	Adjustment to Property Tax Expense	$	(230,913)	L2 - L1

Notes and Source
A: UNS Gas Filing, Schedule C-2, page 4, line 7
B: Amounts taken from Company workpapers used to calculate its property tax expense adjustment

Line	**Utility Plant in Service Taxes**		Transmission		Distribution		General/ Intangible		Total
4	Total Net Plant in Service - Rate Base	$	12,465,045	$	177,788,678	$	13,656,266	$	203,909,989
5	Less: Licensed Transportation in Rate Base					$	(3,786,247)	$	(3,786,247)
6	Less: Land Cost & Rights of Way in Rate Base	$	(55,514)	$	(171,343)	$	(332,698)	$	(559,555)
7	Less: Environmental Property in Rate Base	$	(539,039)	$	(3,264,648)	$	(238,708)	$	(4,042,395)
8	Plus: Land FCV Per Arizona Dept. of Revenue			$	966,162	$	93,000	$	1,059,162
9	Plus: Materials & Supplies in Rate Base			$	2,010,060			$	2,010,060
10	Plant in Service Full Cash Value	$	11,870,492	$	177,328,909	$	9,391,613	$	198,591,014
11	Assessment Ratio*		22.0%		22.0%		22.0%		
12	Taxable Value	$	2,611,508	$	39,012,360	$	2,066,155	$	43,690,023
13	Average Tax Rate		7.6127%		7.6127%		7.6127%		
14	Property Tax	$	198,806	$	2,969,894	$	157,290	$	-
15	Environmental Property in Rate Base	$	539,039	$	3,264,648	$	238,708		
16	Statutory Full Cash Value Adjustment		50%		50%		50%		
17	Environmental Full Cash Value	$	269,520	$	1,632,324	$	119,354	$	-
18	Assessment Ratio*		22.0%		22.0%		22.0%		22.0%
19	Taxable Value	$	59,294	$	359,111	$	26,258	$	-
20	Average Tax Rate		7.6127%		7.6127%		7.6127%		
21	Property Tax	$	4,514	$	27,338	$	1,999	$	-
22	Total Property Taxes	$	203,320	$	2,997,232	$	159,289	$	3,359,841
23	Property Taxes on Leased Property	$	-	$	-	$	19,325 a	$	19,325
24	Total Property Tax Expense	$	203,320	$	2,997,232	$	178,614	$	3,379,166
25	Less: Recorded Property Taxes Excluding Call Center	$	(167,683)	$	(1,981,552)	$	(106,770)	$	(2,256,005)
26	Property Tax Expense Adjustment	$	35,637	$	1,015,680	$	71,844	$	1,123,161

a: Property Tax for Leases calculated as follows (amounts taken from Company workpaper)

Line			Primary Value		Secondary Value		Total
	Cottonwood Lease						
27	Full Cash Value	$	962,504	$	1,145,159		
28	Assessment Ratio*		22.0%		22.0%		
29	Taxable Value	$	211,751	$	251,935		
30	Tax Rate		5.6883%		1.3479%		
31	Property Tax	$	12,045	$	3,396	$	15,441
	Nogales Lease						
32	Full Cash Value	$	432,493				
33	Assessment Ratio*		22.0%				
34	Taxable Value	$	95,148				
35	Tax Rate		10.2038%				
36	Property Tax	$	9,709				
37	Percentage Allocated to UNS Gas		40%				
38	Property Taxes Allocated	$	3,884			$	3,884
39	Total Lease Taxes					$	19,325

* 2009 Arizona Statutory Assessment Ratio 22.0%

FERC 408

UNS Gas, Inc.
Payroll and Payroll Tax Expense

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule C-12

Line No.	Description	Amount (A)	Reference
1	Total Adjusted O&M Payroll Expense Including Overtime Per Filing	$ 7,750,405	A
2	RUCO Recommended Adjusted O&M Payroll Expense Including Overtime	$ 7,524,665	B
3	RUCO Adjustment to Adjusted O&M Payroll Expense	$ (225,740)	L2 - L1
4	Total Pro Forma Payroll Tax Expense Per Filing	$ 888,084	page 2
5	RUCO Recommended Pro Forma Payroll Tax Expense	$ 863,202	page 2
6	RUCO Adjustment to Payroll Tax Expense	$ (24,882)	L5 - L4

Notes and Source

Company workpaper UNSG0571/02586 and related Excel file

A: Amount from Company workpaper UNSG0571/02586 calculated from the following amounts:

7	2009 & 2010 Wage Increase	$ 6,034,999
8	Adjusted Overtime	$ 914,247
9	Estimate Allocated from CLR Accounts	$ 801,159
10	Total Adjusted O&M Payroll Expense Including Overtime Per Filing	$ 7,750,405

B: RUCO recommended amount calculated as follows:

11	2009 Wage Increase (reflects removal of 3% wage increase for 2010)	$ 5,859,222
12	Adjusted Overtime	$ 887,618
13	Estimate Allocated from CLR Accounts	$ 777,824
14	RUCO Recommended Adjusted O&M Payroll Expense Including Overtime	$ 7,524,665

UNS Gas, Inc.
Payroll and Payroll Tax Expense

Test Year Ended June 30, 2008

Line No.	Description	Per UNS Gas (A)	Per RUCO (B)	RUCO Adjustment (C)
	Medicare			
1	Total Adjusted Payroll Including Overtime	$ 11,166,981	$ 10,841,729	
2	Medicare Tax Rate	1.45%	1.45%	
3	Pro Forma Medicare Tax Per Filing	$ 161,921	$ 157,205	$ (4,716)
	OASDI			
4	Total Adjusted Payroll Including Overtime	$ 11,166,981	$ 10,841,729	
5	Less: Wages in Excess of $102,000	$ (99,577)	$ (99,577)	
6	OASDI Tax Base	$ 11,067,404	$ 10,742,152	
7	OASDI Tax Rate	6.20%	6.20%	
8	Pro Forma OASDI Tax	$ 686,179	$ 666,013	$ (20,166)
	Federal/State Unemployment Tax			
	Number of Employees			
9	UNSG Classified	118	118	
10	UNSG Unclassified	86	86	
11	Total Employees	204	204	
12	Taxable Wages	$ 7,000	$ 7,000	
13	Tax Base	$ 1,428,000	$ 1,428,000	
14	Tax Rate	2.80%	2.80%	
15	Pro Forma FUI/SUI	$ 39,984	$ 39,984	$ -
16	Total Pro Forma Payroll Tax Expense	$ 888,084	$ 863,202	$ (24,882)

Notes and Source
Col. A: Amounts from Company workpaper UNSG0571/02608
Col. B: Total adjusted payroll including overtime on Line 1 reflects 3% increase for 2009 only

Attachment RCS-3

Excerpts from NARUC-sponsored Audits of the Expenditures of the American Gas Association

AUDIT REPORT ON THE EXPENDITURES

OF THE

AMERICAN GAS ASSOCIATION

(For the 12 month period ended December 31,1999)

JUNE 2001

**COMMITTEE ON
UTILITY ASSOCIATION OVERSIGHT**

**National Association of
Regulatory Utility Commissioners
1101 Vermont Avenue; Suite 200
Washington, D.C. 20005**

Telephone No. (202) 1898-2200

AMERICAN GAS ASSOCIATION
SUMMARY OF EXPENSES
FOR THE YEAR ENDED DECEMBER 31,1999

EXPENSE CATEGORY	PERCENTAGE
Public Affairs	15.43%
Communications	11.64%
Media Communications:	
Commercial Equipment	4.47%
Environmental	0.74 %
Promotional	0.74%
Residential Equipment	2.96%
Corporate Affairs & International	11.30%
General Counsel & Corporate Secretary	4.02%
Regulatory Affairs	11.20%
Marketing Services	15.02%
Operating & Engineering Services	14.70%
Policy & Analysis	12.07%
Industry Finance & Admin. Programs	2.94 %
General & Administrative Expense	0.00%
TOTAL	107.23% *

* Expense in excess of 100% not funded by dues.

Note: The table above was prepared by the Staff Subcommittee on Utility Association Oversight and should be read in conjunction with the audited financial statements and schedules contained within this report. The expense categories listed above relate to audit definitions found on page III-3 herein.

American Gas Association
Expenditures Funded by Member Dues
For the Year Ended December 31, 1999

Group Number	Group Name	Net Expense		Adjustments	G&A Allocation (5)	Adjusted Net Expense	% of Dues
03	Public Affairs	4,147,682	3, 4	(1,690,669)	455,752	2,912,765	15.43%
03	Communications		4	1,698,695	498,479	2,197,174	11.64%
08	Media Communications						
	Commercial Equipment	759,932	1,2	61,868	21,400	843,200	4.47%
	Environmental	126,708	1,2	10,316	3,568	140,592	0.74%
	Promotional	126,708	1,2	10,316	3,568	140,592	0.74%
	Residential Equipment	503,934	1,2	41,027	14,191	559,152	2.96%
06. 16	Corporate Affairs and International	1,483,688	3	(5,217)	655,144	2,133,615	11.30%
05	General Counsel & Corp. Secretary	588,436	3		170,907	759,343	4.02%
09	Regulatory Affairs	1,492,676	3	194,393	427,268	2,114,337	11.20%
08	Marketing Services	4,654,503	1, 2	(2,302,920)	484,237	2,835,820	15.02%
14	Operating & Engineering Services	1,949,534			826,051	2,775.585	14.70%
07	Policy & Analysis	1,374,743	1	277.704	626,659	2,279,106	12.07%
12	Industry Finance & Admin. Programs	498,349			56,969	555,318	2.94%
01.10.11	General & Administrative Expense	4,247,002	3	(2,809)	(4,244,193)		0.00%
	Grand Total	21,953,895		$ (1,707,296)	$ -	$ 20,246,599	107.23%

Adjustments as a result of A.G.A./NARUC Oversight Committee Staff agreement.

1 Allocation of Group Vice President's salaries.
2 Media Communications portion of division expenses.
3 Expenses transferred to Government Relations.
4 Breakout of communications portion of division expenses
5 G&A allocated on basis of equivalent full-time employees during 1999.

AMERICAN GAS ASSOCIATION

Definitions of Functional Cost Centers
For the Year Ended December 31, 1999

COST CENTER	DESCRIPTION
03	Communications develops informational materials for member companies and consumers and coordinates all media activity.
	Public affairs provides members with information on legislative developments: prepares testimony, comments, and filings regarding legislative activities; lobbies on behalf of the industry.
08	Media Communications manages the development and placement of consumer information advertisements in national print and electronic media.
	Commercial Equipment - explains the use of specific models of commercial/institutional equipment, emphasizing cost savings energy efficiency and the other additional benefits of natural gas.
	Environmental - describes the environmental benefits of natural gas to advocate its increased use to replace other fuels.
	Industrial Equipment - explains cost-savings, energy-savings and other benefits provided by the industrial applicationsof specific equipment.
	Institutional - to enhance the image of the natural gas industry as a business entity.
	Power Generation Natural Gas Equipment - explains cost-savings. energy-savings and other benefits provided by specific equipment for generating power.
	Promotional - promotes the efficient use of natural gas by emphasizing the resource efficiency, cost and other inherent qualities of natural gas.
	Residential Equipment - explains cost-savings, energy-savings, and other related benefits to the customer/user provided by certain models of residential natural gas appliances such as boiler, furnaces, ranges and water heaters.
12	Finance & Administration develops and implements programs in such areas as accounting, human resources and risk management for member companies.

05 General Counsel & Corporate Secretaw provides legal counsel to the Association

06 Corporate Affairs provides opportun'ities for interaction between member companies and the financial community. The focus is to promote interest in the investment opportunities in the industry.

09 Regulatory Affairs provides members with information on FERC and state regulatory developments; prepares testimony, comments, and filings regarding regulatory activities.

08 Market Development assists members in their efforts to encourage the most efficient utilization of gas energy by exchanging information about marketing trends, conducting utilization efficiency programs and exploring market opportunities.

14 Operating & Engineering develops and implements programs and practices to meet the operational, safety and engineering needs of the industry.

07 Policy & Analysis identifies the need for and conducts energy analyses and modeling efforts in the areas of gas supply and demand, economics and the environment.

General & Administrative includes:

01 Office of the President provides senior management guidance for all A.G.A. activities.

10 Human Resources develops and administers employee programs and provides general office and personnel services.

11 Finance and Administration develops and administers financial accounting and treasury services and maintains computers services capability.

* Pipeline Research: develops, manages and evaluates pipeline research projects that provide advances in technology.

* Reserve: Extraordinary adjustments are recorded as reserve charges. Major adjustments are identified in the audited financial statements.

* Not funded by current year General Fund Dues.

AUDIT REPORT ON THE EXPENDITURES

OF THE

AMERICAN GAS ASSOCIATION

(For the 12 month period ended December 31, 1998)

JANUARY 2000

COMMITTEE ON
UTILITY ASSOCIATION OVERSIGHT

National Association of
Regulatory Utility Commissioners
1101 Vermont Avenue, N.W., Suite 200
Washington, D.C. 20005

Telephone No. (202) 898-2200

AMERICAN GAS ASSOCIATION
SUMMARY OF EXPENSES
FOR THE YEAR ENDED DECEMBER 31, 1998

EXPENSE CATEGORY	PERCENTAGE
Communications	10.27%
MEDIA COMMUNICATIONS:	
Commercial Equipment	5.96%
Environmental	3.37%
Industrial Equipment	1.36%
Promotional	1.46%
Residential Equipment	8.40%
Finance & Administration Services	12.17%
General Counsel & Corporate Secretary	5.54%
Government Relations	23.86%
Marketing Services	16.20%
Meeting Services	-0.18%
Operating & Engineering Services	4.90%
Planning & Analysis	9.51%
General & Administrative Expense	0.00%
TOTAL	102.82% *

* Expense in excess of 100% not funded by dues.

Note: The table above was prepared by the Staff Subcommittee on Utility Association Oversight and should be read in conjunction with the audited financial statements and schedules contained within this report. The expense categories listed above relate to audit definitions found on page III-3 herein.

American Gas Association
Expenditures Funded by Member Dues
For the Year Ended December 31, 1998

Group Number	Group Name	Net Expense		Adjustments	G&A Allocation (4)	Adjusted Net Expense	% of Dues
03	Communications	1,561,612	2	(2,679)	430,782	1,989,715	10.27%
13	Media Communications						
	Commercial Equipment	1,105,739	1,2	31,943	17,848	1,155,530	5.96%
	Environmental	625,598	1,2	18,072	10,098	653,768	3.37%
	Industrial Equipment	252,954	1,2	7,307	4,083	264,344	1.36%
	Promotional	270,820	1,2	7,823	4,372	283,015	1.46%
	Residential Equipment	1,557,378	1,2	44,990	25,139	1,627,507	8.40%
06	Finance & Administration Services	1,797,937	3	(13,893)	574,377	2,358,420	12.17%
05	General Counsel & Corp. Secretary	938,797	3	(8,566)	143,594	1,073,825	5.54%
09	Government Relations	3,802,555	3	22,459	800,025	4,625,039	23.86%
08	Marketing Services	2,693,462	1	(107,456)	553,863	3,139,869	16.20%
04	Meeting Services	(34,155)		-	-	(34,155)	-0.18%
14	Operating & Engineering Services	661,825		-	287,188	949,013	4.90%
07	Policy & Analysis	1,392,718		-	451,296	1,844,014	9.51%
01,10,11	General & Administrative Expense	3,302,665		-	(3,302,665)	0	0.00%
	Grand Total	19,929,905		$ 0	$ 0	$ 19,929,905	102.84%

Adjustments as a result of A.G.A./NARUC Oversight Committee Staff agreement.

1 Allocation of Group Vice President's salaries.
2 Media Communications portion of division expenses.
3 Expenses transferred to Government Relations.
4 G&A allocated on basis of equivalent full-time employees during 1997.

AMERICAN GAS ASSOCIATION

Definitions of Functional Cost Centers
For the Year Ended December 31, 1998

COST CENTER	DESCRIPTION
03	Communications develops informational materials for member companies and consumers and coordinates all media activity.
13	Media Communications manages the development and placement of consumer information advertisements in national print and electronic media.
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	Industrial Equipment - explains cost-savings, energy-savings and other benefits provided by the industrial applications of specific equipment.
	Promotional - promotes the efficient use of natural gas by emphasizing the resource efficiency, cost and other inherent qualities of natural gas.
	Residential Equipment - explains cost-savings, energy-savings, and other related benefits to the customer/user provided by certain models of residential natural gas appliances such as boiler, furnaces, ranges and water heaters.
06/16	Finance & Administration develops and implements programs in such areas as accounting, human resources and risk management for member companies.
05	General Counsel & Corporate Secretary provides legal counsel to the Association.
09	Government Relations provides members with information on legislative and regulatory developments; prepares testimony, comments, and filings regarding legislative and regulatory activities; lobbies on behalf of the industry.
08	Marketing assists members in their efforts to encourage the most efficient utilization of gas energy by exchanging information about marketing trends, conducting utilization efficiency programs and exploring market opportunities.

04 Meeting Services and Membership Services provides support services for committee meetings and conferences. In addition, coordinates services provided to members.

14 Operating & Engineering develops and implements programs and practices to meet the operational, safety and engineering needs of the industry.

07 Policy & Analysis identifies the need for and conducts energy analyses and modeling efforts in the areas of gas supply and demand, economics and the environment.

General & Administrative includes:

01 Office of the President provides senior management guidance for all A.G.A. activities.

10 Human Resources develops and administers employee programs and provides general office and personnel services.

11 Finance and Administration develops and administers financial accounting and treasury services and maintains computers services capability.

* Pipeline Research: develops, manages and evaluates pipeline research projects that provide advances in technology.

* Reserve: Extraordinary adjustments are recorded as reserve charges. Major adjustments are identified in the audited financial statements.

* Not funded by current year General Fund Dues.

Excerpt from Florida PSC City Gas Company rate case 01152004

State of Florida

Public Service Commission

Capital Circle Office Center 2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE:DECEMBER 23, 2003

TO:DIRECTOR, DIVISION OF THE COMMISSION CLERK & ADMINISTRATIVE SERVICES (BAYÓ)

FROM:DIVISION OF ECONOMIC REGULATION (BRINKLEY, BAXTER, DRAPER, GARDNER, HEWITT, KAPROTH, KENNY, LESTER, LINGO, C. ROMIG, SPRINGER, STALLCUP, WHEELER, WINTERS)
DIVISION OF COMPETITIVE SERVICES (MAKIN)
OFFICE OF THE GENERAL COUNSEL (JAEGER)

RE:DOCKET NO. 030569-GU - APPLICATION FOR RATE INCREASE BY CITY GAS COMPANY OF FLORIDA.

AGENDA:01/06/04 - REGULAR AGENDA - PROPOSED AGENCY ACTION - INTERESTED PERSONS MAY PARTICIPATE

CRITICAL DATES:5-MONTH EFFECTIVE DATE: JANUARY 15, 2004 (PAA RATE CASE)

SPECIAL INSTRUCTIONS:NONE

FILE NAME AND LOCATION:S:\PSC\ECR\WP\City Gas 030569-GU\
Final.RCM
Final Attachments 1-5.123
Final Attachments 6A-7P.123
Final Attachment 8.xls

ISSUE 39: Is City Gas's $(2,847) adjustment to Account 921, Office Supplies and Expenses, for American Gas Association membership dues appropriate?

RECOMMENDATION: No. Account 921, Office Supplies and Expenses, should be reduced by an additional $13,178 for American Gas Association membership dues related to charitable contributions and advertising that is not informational or educational in nature. (C. ROMIG)

STAFF ANALYSIS: On MFR Schedule G-2, Page 17 of 34, the Company included $1,966,495 in its Account 921, Office Supplies and Expense for the 2003 interim year. Included in this amount is $39,277 related to American Gas Association (AGA) membership dues. This was inflated for customer growth and general inflation of 1.0232 to $40,188. On MFR G-2, Page 2 of 34, it removed $2,847 that was labeled as "attributable to lobbying." This represents an adjustment of 7.08%.

In City Gas's last rate case, In re: Request for rate increase by City Gas Company of Florida, Docket No. 000768-GU, Order No. PSC-01-0316-PAA-GU, issued February 5, 2001, the Company removed $4,045 for AGA dues for lobbying. The Commission removed an additional combined amount of $4,970 for memberships, dues and contributions. In re: Application for a rate increase by City Gas Company of Florida, Docket No. 940276-GU, Order No. PSC-94-0957-FOF-GU, issued August 9, 1994, for interim purposes, the Commission disallowed 40% of AGA dues. This order stated that the percentage was based on the 1993 National Association of Regulatory Commission's (NARUC) Audit Report on the Expenditures of the American Gas Association (Audit Report). Order No. PSC-94-0957-FOF-GU further stated that this reduction was consistent with adjustments made in rate cases involving other gas companies. In the final order in Docket No. 940276-GU, Order No. PSC-94-1570-FOF-GU, issued December 19, 1994, the Commission removed 40.48% of AGA dues "which were related to lobbying and advertising that did not meet the criteria of being informational or educational in nature." In re: Request for rate increase by Florida Division of Chesapeake Utilities Corporation, Docket No. 000108-GU, Order No. PSC-00-2263-FOF-GU, issued November 28, 2000, the Commission removed 45.10% of AGA dues.

The latest NARUC Audit Report on AGA expenditures that Staff was able to locate is dated June, 2001, for the twelve-month period ended December 31, 1999. By a review of the Summary of Expenses, it appears that 41.65% of 1999 AGA expenditures are for lobbying and advertising. Staff has not been able to locate a more recent NARUC Audit Report of the AGA expenditures. However, because approximately 40% appears to have been consistent over a number of years, Staff believes it is not unreasonable to assume that 40% is representative of 2003 and 2004 expenditures and recommends that 40% of AGA dues be disallowed in this proceeding.

From information supplied by the Company, AGA dues were $39,277 in 2003. According to recommendations in Issue 44 and 45, Account 921 should be trended on inflation only at 2.0% for 2004. On that basis the 2004 amount is $40,063 ($39,277 x 1.02). Disallowing 40% would result in disallowing $16,025 for 2004. The Company's $2,847 adjustment reduces Staff's adjustment to $13,178 ($16,025 - $2,847) for 2004. This position follows past Commission practice of placing charitable contributions and advertising that is not informational or educational in nature below the line.

Based on the above analysis, Account 921, Office Supplies and Expenses, should be reduced by an additional $13,178 for AGA membership dues related to charitable contributions and advertising that is not informational or educational in nature.

The Company is in agreement with this adjustment.

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Attachment RCS-5
Copies of UNS Gas' Responses to Data Requests and Workpapers Referenced in the Direct Testimony and Schedules of Ralph C. Smith

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
TF 6-28	Working capital adjustment detail - Customer deposits	No	8	2 - 9
TF 6.64	Description of SERP and incentive compensation programs available to officers and employees	No	68	10 - 77
TF 6.103	UNS Gas' Accounting adjustments deviating from prior Commission decisions	No	1	78
TF 6.92	UNS Gas' description of incentive compensation plans	No	4	79 - 82
	UniSource Energy's March 23, 2009 Proxy Report (publicly available)	No	51	83 - 133
RUCO 1.94	UNS Gas' fleet fuel expense supporting data	No	4	134-137
	Public information on Arizona gasoline prices	No	5	138-142
TF 6.68	Explanation of rate case expense adjustment correction	No	3	143-145
RUCO 1.90	Current average known property tax rate	No	2	146-147
UNSG0571/02839	UNS Gas' Accumulated Deferred Income Taxes Workpaper	No	1	148
UNSG0571/02244 & related excel file	UNS Gas' Depreciation Workpapers	No	8	149-156
TF 6.54	American Gas Association Dues Expense	No	11	157-167
RUCO 1.48	Copies of American Gas Association Dues Invoices	No	4	168-171
UNSG0571/02500	UNS Gas' American Gas Association Dues Workpapers	No	1	172
UNSG0571/02585-86	UNS Gas' Outside legal costs workpapers	No	12	173-184
UNSG0571/02563 - 74 & related excel file	UNS Gas' Payroll Expense Workpapers	No	2	185-186
UNSG0571/02608	UNS Gas' Payroll Tax Expense Workpapers	No	1	187
	Total Pages Including this Page		187	

**UNS GAS, INC.'S RESPONSE TO
STAFF'S FIFTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
April 17, 2009**

TF 6.28: For the Company's details of adjustments to working capital, B-5, page 2 of 3, M&S and Prepayments.

a. Please provide the monthly amounts of M&S for the 60 months ending December 31, 2008.
b. Please provide the monthly amounts of Prepayments for the 60 months ending December 31, 2008.

Please also provide the monthly amounts of Customer Deposits for the 60 months ending December 31, 2008.

RESPONSE:

a. Please see the Excel file TF 6.28(a) on the enclosed CD for the monthly amounts of M&S for the period January 2006 through December 2008. The prior months January 2004 – December 2005 were provided in the prior rate case.

b. Please see the Excel file TF 6.28(b) on the enclosed CD for the monthly amounts of Prepayments for the period January 2006 through December 2008. The prior months January 2004 – December 2005 were provided in the prior rate case.

c. Please see the Excel file TF 6.28(c) on the enclosed CD for the monthly amounts of Customer Deposits for the period January 2006 through December 2008. The prior months January 2004 – December 2005 were provided in the prior rate case.

The Excel files on the CD are not identified by Bates numbers.

RESPONDENT: Mina Briggs

WITNESS: Dallas Dukes

UNS GAS, INC.
STAFF'S 6TH SET: TF 6-28a - Materials and Supplies 60 months ending December 2008

JANUARY 2006 THROUGH DECEMBER 2008
Note: January 2004 - December 2005 Provided in prior rate case.

Acct	Account Title	Date	Beg Balance	Period Net	Balance
12600	Undistributed Stores Expense	JAN-06	$110,243.38	$44,419.42	$154,662.80
12500	Materials & Supplies		$1,888,849.07	$156,693.08	$2,045,542.15
		Sum	$1,999,092.45	$201,112.50	$2,200,204.95
12500	Materials & Supplies	FEB-06	$2,045,542.15	($134,579.89)	$1,910,962.26
12600	Undistributed Stores Expense		$154,662.80	$98,892.29	$253,555.09
		Sum	$2,200,204.95	($35,687.60)	$2,164,517.35
12500	Materials & Supplies	MAR-06	$1,910,962.26	$10,218.98	$1,921,181.24
12600	Undistributed Stores Expense		$253,555.09	$34,599.12	$288,154.21
		Sum	$2,164,517.35	$44,818.10	$2,209,335.45
12500	Materials & Supplies	APR-06	$1,921,181.24	($187,979.01)	$1,733,202.23
12600	Undistributed Stores Expense		$288,154.21	($28,702.16)	$259,452.05
		Sum	$2,209,335.45	($216,681.17)	$1,992,654.28
12500	Materials & Supplies	MAY-06	$1,733,202.23	$139,631.20	$1,872,833.43
12600	Undistributed Stores Expense		$259,452.05	$4,383.75	$263,835.80
		Sum	$1,992,654.28	$144,014.95	$2,136,669.23
12600	Undistributed Stores Expense	JUN-06	$263,835.80	($43,329.01)	$220,506.79
12500	Materials & Supplies		$1,872,833.43	$106,638.95	$1,979,472.38
		Sum	$2,136,669.23	$63,309.94	$2,199,979.17
12500	Materials & Supplies	JUL-06	$1,979,472.38	$5,856.46	$1,985,328.84
12600	Undistributed Stores Expense		$220,506.79	($10,998.56)	$209,508.23
		Sum	$2,199,979.17	($5,142.10)	$2,194,837.07
12500	Materials & Supplies	AUG-06	$1,985,328.84	$19,582.02	$2,004,910.86
12600	Undistributed Stores Expense		$209,508.23	($1,141.18)	$208,367.05
		Sum	$2,194,837.07	$18,440.84	$2,213,277.91
12500	Materials & Supplies	SEP-06	$2,004,910.86	$32,555.25	$2,037,466.11
12600	Undistributed Stores Expense		$208,367.05	$4,325.73	$212,692.78
		Sum	$2,213,277.91	$36,880.98	$2,250,158.89
12500	Materials & Supplies	OCT-06	$2,037,466.11	($47,414.74)	$1,990,051.37
12600	Undistributed Stores Expense		$212,692.78	$26,616.65	$239,309.43
		Sum	$2,250,158.89	($20,798.09)	$2,229,360.80
12500	Materials & Supplies	NOV-06	$1,990,051.37	$23,911.77	$2,013,963.14
12600	Undistributed Stores Expense		$239,309.43	($12,444.16)	$226,865.27
		Sum	$2,229,360.80	$11,467.61	$2,240,828.41
12500	Materials & Supplies	DEC-06	$2,013,963.14	($54,840.35)	$1,959,122.79
12600	Undistributed Stores Expense		$226,865.27	($24,623.30)	$202,241.97
		Sum	$2,240,828.41	($79,463.65)	$2,161,364.76
12500	Materials & Supplies	Jan-07	$1,959,122.79	($48,995.66)	$1,910,127.13
12600	Undistributed Stores Expense		$202,241.97	($9,677.83)	$192,564.14
		Sum	$2,161,364.76	($58,673.49)	$2,102,691.27
12500	Materials & Supplies	Feb-07	$1,910,127.13	$45,750.59	$1,955,877.72
12600	Undistributed Stores Expense		$192,564.14	$18,119.20	$210,683.34
		Sum	$2,102,691.27	$63,869.79	$2,166,561.06
12500	Materials & Supplies	Mar-07	$1,955,877.72	($44,629.56)	$1,911,248.16
12600	Undistributed Stores Expense		$210,683.34	($12,384.75)	$198,298.59
		Sum	$2,166,561.06	($57,014.31)	$2,109,546.75
12500	Materials & Supplies	Apr-07	$1,911,248.16	$75,730.94	$1,986,979.10

UNS GAS, INC.
STAFF'S 6TH SET: TF 6-28b. Prepayments
JANUARY 2006 THROUGH DECEMBER 2008
Note: January 2004 - December 2005 Provided in prior rate case.

Acct	Account Title	Date	Beg Balance	Period Net	Balance
14050	Prepaid Taxes	JAN-06	$0.00	$0.00	$0.00
14010	Prepaid Insurance		$181,140.02	($32,100.33)	$149,039.69
14100	Other Prepaids		$66,125.01	($26,262.89)	$39,862.12
		Sum	$247,265.03	($58,363.22)	$188,901.81
14100	Other Prepaids	FEB-06	$39,862.12	($3,623.83)	$36,238.29
14010	Prepaid Insurance		$149,039.69	($32,100.33)	$116,939.36
14050	Prepaid Taxes		$0.00	$0.00	$0.00
		Sum	$188,901.81	($35,724.16)	$153,177.65
14100	Other Prepaids	MAR-06	$36,238.29	$86,278.42	$122,516.71
14010	Prepaid Insurance		$116,939.36	($32,100.33)	$84,839.03
14050	Prepaid Taxes		$0.00	$0.00	$0.00
		Sum	$153,177.65	$54,178.09	$207,355.74
14100	Other Prepaids	APR-06	$122,516.71	($66,676.08)	$55,840.63
14010	Prepaid Insurance		$84,839.03	($32,100.33)	$52,738.70
14050	Prepaid Taxes		$0.00	$0.00	$0.00
		Sum	$207,355.74	($98,776.41)	$108,579.33
14100	Other Prepaids	MAY-06	$55,840.63	($6,980.08)	$48,860.55
14010	Prepaid Insurance		$52,738.70	($32,100.33)	$20,638.37
14050	Prepaid Taxes		$0.00	$0.00	$0.00
		Sum	$108,579.33	($39,080.41)	$69,498.92
14050	Prepaid Taxes	JUN-06	$0.00	$84,663.93	$84,663.93
14010	Prepaid Insurance		$20,638.37	$305,130.13	$325,768.50
14100	Other Prepaids		$48,860.55	$88,268.37	$137,128.92
		Sum	$69,498.92	$478,062.43	$547,561.35
14100	Other Prepaids	JUL-06	$137,128.92	($6,980.08)	$130,148.84
14010	Prepaid Insurance		$325,768.50	$22,895.58	$348,664.08
14050	Prepaid Taxes		$84,663.93	($9,673.15)	$74,990.78
		Sum	$547,561.35	$6,242.35	$553,803.70
14100	Other Prepaids	AUG-06	$130,148.84	($6,980.08)	$123,168.76
14010	Prepaid Insurance		$348,664.08	($32,714.42)	$315,949.66
14050	Prepaid Taxes		$74,990.78	($19,697.77)	$55,293.01
		Sum	$553,803.70	($59,392.27)	$494,411.43
14100	Other Prepaids	SEP-06	$123,168.76	$37,376.07	$160,544.83
14010	Prepaid Insurance		$315,949.66	($32,714.42)	$283,235.24
14050	Prepaid Taxes		$55,293.01	($22,107.56)	$33,185.45
		Sum	$494,411.43	($17,445.91)	$476,965.52
14100	Other Prepaids	OCT-06	$160,544.83	($11,316.27)	$149,228.56
14010	Prepaid Insurance		$283,235.24	($32,714.42)	$250,520.82
14050	Prepaid Taxes		$33,185.45	($16,744.54)	$16,440.91
		Sum	$476,965.52	($60,775.23)	$416,190.29
14100	Other Prepaids	NOV-06	$149,228.56	($11,316.27)	$137,912.29
14010	Prepaid Insurance		$250,520.82	($32,714.42)	$217,806.40
14050	Prepaid Taxes		$16,440.91	($16,440.91)	$0.00
		Sum	$416,190.29	($60,471.60)	$355,718.69
14100	Other Prepaids	DEC-06	$137,912.29	($460.32)	$137,451.97
14010	Prepaid Insurance		$217,806.40	($32,714.42)	$185,091.98
14050	Prepaid Taxes		$0.00	$0.00	$0.00
		Sum	$355,718.69	($33,174.74)	$322,543.95
14010	Prepaid Insurance	JAN-07	$185,091.98	($32,714.42)	$152,377.56
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14100	Other Prepaids		$137,451.97	($4,336.19)	$133,115.78

UNS GAS, INC.
STAFF'S 6TH SET: TF 6-28b. Prepayments
JANUARY 2006 THROUGH DECEMBER 2008
Note: January 2004 - December 2005 Provided in prior rate case.

Acct	Account Title	Date	Beg Balance	Period Net	Balance
		Sum	$322,543.95	($37,050.61)	$285,493.34
14010	Prepaid Insurance	FEB-07	$152,377.56	($32,714.42)	$119,663.14
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14100	Other Prepaids		$133,115.78	$33,587.15	$166,702.93
		Sum	$285,493.34	$872.73	$286,366.07
14100	Other Prepaids	MAR-07	$166,702.93	($109,794.38)	$56,908.55
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14010	Prepaid Insurance		$119,663.14	($32,714.42)	$86,948.72
		Sum	$286,366.07	($142,508.80)	$143,857.27
14010	Prepaid Insurance	APR-07	$86,948.72	($32,714.42)	$54,234.30
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14100	Other Prepaids		$56,908.55	($8,128.52)	$48,780.03
		Sum	$143,857.27	($40,842.94)	$103,014.33
14100	Other Prepaids	MAY-07	$48,780.03	($8,128.52)	$40,651.51
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14010	Prepaid Insurance		$54,234.30	($32,714.42)	$21,519.88
		Sum	$103,014.33	($40,842.94)	$62,171.39
14010	Prepaid Insurance	JUN-07	$21,519.88	$326,172.83	$347,692.71
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14100	Other Prepaids		$40,651.51	$107,126.78	$147,778.29
		Sum	$62,171.39	$433,299.61	$495,471.00
14010	Prepaid Insurance	JUL-07	$347,692.71	$21,532.58	$369,225.29
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14100	Other Prepaids		$147,778.29	($8,128.52)	$139,649.77
		Sum	$495,471.00	$13,404.06	$508,875.06
14100	Other Prepaids	AUG-07	$139,649.77	($8,128.52)	$131,521.25
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14010	Prepaid Insurance		$369,225.29	($34,668.42)	$334,556.87
		Sum	$508,875.06	($42,796.94)	$466,078.12
14010	Prepaid Insurance	SEP-07	$334,556.87	($34,668.42)	$299,888.45
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14100	Other Prepaids		$131,521.25	($38,924.09)	$92,597.16
		Sum	$466,078.12	($73,592.51)	$392,485.61
14010	Prepaid Insurance	OCT-07	$299,888.45	($34,668.42)	$265,220.03
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14100	Other Prepaids		$92,597.16	$38,308.88	$130,906.04
		Sum	$392,485.61	$3,640.46	$396,126.07
14010	Prepaid Insurance	NOV-07	$265,220.03	($34,668.42)	$230,551.61
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14100	Other Prepaids		$130,906.04	($7,619.71)	$123,286.33
		Sum	$396,126.07	($42,288.13)	$353,837.94
14100	Other Prepaids	DEC-07	$123,286.33	$15,397.79	$138,684.12
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14010	Prepaid Insurance		$230,551.61	($34,668.42)	$195,883.19
		Sum	$353,837.94	($19,270.63)	$334,567.31
14050	Prepaid Taxes	JAN-08	$0.00	$0.00	$0.00
14010	Prepaid Insurance		$195,883.19	($34,668.42)	$161,214.77
14100	Other Prepaids		$138,684.12	$40,061.70	$178,745.82
		Sum	$334,567.31	$5,393.28	$339,960.59
14050	Prepaid Taxes	FEB-08	$0.00	$0.00	$0.00
14010	Prepaid Insurance		$161,214.77	($34,668.42)	$126,546.35

UNS GAS, INC.
STAFF'S 6TH SET: TF 6-28b. Prepayments
JANUARY 2006 THROUGH DECEMBER 2008
Note: January 2004 - December 2005 Provided in prior rate case.

Acct	Account Title	Date	Beg Balance	Period Net	Balance
14100	Other Prepaids		$178,745.82	($7,817.30)	$170,928.52
		Sum	$339,960.59	($42,485.72)	$297,474.87
14050	Prepaid Taxes	MAR-08	$0.00	$0.00	$0.00
14010	Prepaid Insurance		$126,546.35	($34,668.42)	$91,877.93
14100	Other Prepaids		$170,928.52	$26,867.03	$197,795.55
		Sum	$297,474.87	($7,801.39)	$289,673.48
14050	Prepaid Taxes	APR-08	$0.00	$0.00	$0.00
14010	Prepaid Insurance		$91,877.93	($34,668.42)	$57,209.51
14100	Other Prepaids		$197,795.55	($7,817.30)	$189,978.25
		Sum	$289,673.48	($42,485.72)	$247,187.76
14100	Other Prepaids	MAY-08	$189,978.25	($7,817.30)	$182,160.95
14010	Prepaid Insurance		$57,209.51	($34,668.42)	$22,541.09
14050	Prepaid Taxes		$0.00	$0.00	$0.00
		Sum	$247,187.76	($42,485.72)	$204,702.04
14050	Prepaid Taxes	JUN-08	$0.00	$105.59	$105.59
14010	Prepaid Insurance		$22,541.09	$189,018.71	$211,559.80
14100	Other Prepaids		$182,160.95	($136,933.05)	$45,227.90
		Sum	$204,702.04	$52,191.25	$256,893.29
14100	Other Prepaids	Jul-08	$45,227.90	($7,817.30)	$37,410.60
14010	Prepaid Insurance		$211,559.80	$198,230.35	$409,790.15
14050	Prepaid Taxes		$105.59	($105.59)	$0.00
		Sum	$256,893.29	$190,307.46	$447,200.75
14050	Prepaid Taxes	Aug-08	$0.00	$0.00	$0.00
14010	Prepaid Insurance		$409,790.15	($37,253.65)	$372,536.50
14100	Other Prepaids		$37,410.60	($11,644.71)	$25,765.89
		Sum	$447,200.75	($48,898.36)	$398,302.39
14100	Other Prepaids	Sep-08	$25,765.89	$24,366.60	$50,132.49
14010	Prepaid Insurance		$372,536.50	($65,002.17)	$307,534.33
14050	Prepaid Taxes		$0.00	$0.00	$0.00
		Sum	$398,302.39	($40,635.57)	$357,666.82
14100	Other Prepaids	Oct-08	$50,132.49	($3,989.92)	$46,142.57
14010	Prepaid Insurance		$307,534.33	($34,170.49)	$273,363.84
14050	Prepaid Taxes		$0.00	$0.00	$0.00
		Sum	$357,666.82	($38,160.41)	$319,506.41
14100	Other Prepaids	Nov-08	$46,142.57	($3,989.92)	$42,152.65
14010	Prepaid Insurance		$273,363.84	($34,170.49)	$239,193.35
14050	Prepaid Taxes		$0.00	$0.00	$0.00
		Sum	$319,506.41	($38,160.41)	$281,346.00
14100	Other Prepaids	Dec-08	$42,152.65	$66,032.50	$108,185.15
14010	Prepaid Insurance		$239,193.35	($34,170.49)	$205,022.86
14050	Prepaid Taxes		$0.00	$0.00	$0.00
		Sum	$281,346.00	$31,862.01	$313,208.01

UNS GAS, INC.
STAFF'S 6TH SET: TF 6-28a - Materials and Supplies 60 months ending December 2008

JANUARY 2006 THROUGH DECEMBER 2008
Note: January 2004 - December 2005 Provided in prior rate case.

Acct	Account Title	Date	Beg Balance	Period Net	Balance
12600	Undistributed Stores Expense		$198,298.59	($7,690.41)	$190,608.18
		Sum	$2,109,546.75	$68,040.53	$2,177,587.28
12500	Materials & Supplies	May-07	$1,986,979.10	($109,031.73)	$1,877,947.37
12600	Undistributed Stores Expense		$190,608.18	$35,535.22	$226,143.40
		Sum	$2,177,587.28	($73,496.51)	$2,104,090.77
12500	Materials & Supplies	Jun-07	$1,877,947.37	$25,843.86	$1,903,791.23
12600	Undistributed Stores Expense		$226,143.40	$5,881.03	$232,024.43
		Sum	$2,104,090.77	$31,724.89	$2,135,815.66
12500	Materials & Supplies	Jul-07	$1,903,791.23	$10,661.45	$1,914,452.68
12600	Undistributed Stores Expense		$232,024.43	$7,979.79	$240,004.22
		Sum	$2,135,815.66	$18,641.24	$2,154,456.90
12500	Materials & Supplies	Aug-07	$1,914,452.68	($104,471.06)	$1,809,981.62
12600	Undistributed Stores Expense		$240,004.22	$2,840.25	$242,844.47
		Sum	$2,154,456.90	($101,630.81)	$2,052,826.09
12500	Materials & Supplies	Sep-07	$1,809,981.62	($12,009.72)	$1,797,971.90
12600	Undistributed Stores Expense		$242,844.47	($317.12)	$242,527.35
		Sum	$2,052,826.09	($12,326.84)	$2,040,499.25
12500	Materials & Supplies	Oct-07	$1,797,971.90	($68,994.55)	$1,728,977.35
12600	Undistributed Stores Expense		$242,527.35	($6,458.67)	$236,068.68
		Sum	$2,040,499.25	($75,453.22)	$1,965,046.03
12500	Materials & Supplies	Nov-07	$1,728,977.35	($7,937.96)	$1,721,039.39
12600	Undistributed Stores Expense		$236,068.68	($9,964.26)	$226,104.42
		Sum	$1,965,046.03	($17,902.22)	$1,947,143.81
12500	Materials & Supplies	Dec-07	$1,721,039.39	$61,997.97	$1,783,037.36
12600	Undistributed Stores Expense		$226,104.42	$13,299.53	$239,403.95
		Sum	$1,947,143.81	$75,297.50	$2,022,441.31
12500	Materials & Supplies	Jan-08	$1,783,037.36	($17,700.82)	$1,765,336.54
12600	Undistributed Stores Expense		$239,403.95	$3,259.90	$242,663.85
		Sum	$2,022,441.31	($14,440.92)	$2,008,000.39
12500	Materials & Supplies	Feb-08	$1,765,336.54	($43,779.16)	$1,721,557.38
12600	Undistributed Stores Expense		$242,663.85	$33,280.37	$275,944.22
		Sum	$2,008,000.39	($10,498.79)	$1,997,501.60
12500	Materials & Supplies	Mar-08	$1,721,557.38	($55,802.04)	$1,665,755.34
12600	Undistributed Stores Expense		$275,944.22	$23,627.52	$299,571.74
		Sum	$1,997,501.60	($32,174.52)	$1,965,327.08
12500	Materials & Supplies	Apr-08	$1,665,755.34	($57,412.97)	$1,608,342.37
12600	Undistributed Stores Expense		$299,571.74	$2,848.01	$302,419.75
		Sum	$1,965,327.08	($54,564.96)	$1,910,762.12
12500	Materials & Supplies	May-08	$1,608,342.37	$32,977.77	$1,641,320.14
12600	Undistributed Stores Expense		$302,419.75	($13,365.08)	$289,054.67
		Sum	$1,910,762.12	$19,612.69	$1,930,374.81
12500	Materials & Supplies	Jun-08	$1,641,320.14	$27,285.13	$1,668,605.27
12600	Undistributed Stores Expense		$289,054.67	$52,400.46	$341,455.13
		Sum	$1,930,374.81	$79,685.59	$2,010,060.40
12500	Materials & Supplies	Jul-08	$1,668,605.27	($35,747.57)	$1,632,857.70
12600	Undistributed Stores Expense		$341,455.13	$3,565.13	$345,020.26

UNS GAS, INC.
STAFF'S 6TH SET: TF 6-28a - Materials and Supplies 60 months ending December 2008

JANUARY 2006 THROUGH DECEMBER 2008
Note: January 2004 - December 2005 Provided in prior rate case.

Acct	Account Title	Date	Beg Balance	Period Net	Balance
		Sum	$2,010,060.40	($32,182.44)	$1,977,877.96
12600	Undistributed Stores Expense	Aug-08	$345,020.26	$25,047.83	$370,068.09
12500	Materials & Supplies		$1,632,857.70	$1,621.59	$1,634,479.29
		Sum	$1,977,877.96	$26,669.42	$2,004,547.38
12500	Materials & Supplies	Sep-08	$1,634,479.29	($38,540.10)	$1,595,939.19
12600	Undistributed Stores Expense		$370,068.09	$5,853.54	$375,921.63
		Sum	$2,004,547.38	($32,686.56)	$1,971,860.82
12500	Materials & Supplies	Oct-08	$1,595,939.19	($6,154.34)	$1,589,784.85
12600	Undistributed Stores Expense		$375,921.63	$35,781.53	$411,703.16
		Sum	$1,971,860.82	$29,627.19	$2,001,488.01
12500	Materials & Supplies	Nov-08	$1,589,784.85	($13,552.05)	$1,576,232.80
12600	Undistributed Stores Expense		$411,703.16	$23,650.29	$435,353.45
		Sum	$2,001,488.01	$10,098.24	$2,011,586.25
12500	Materials & Supplies	Dec-08	$1,576,232.80	$31,381.20	$1,607,614.00
12600	Undistributed Stores Expense		$435,353.45	$76,313.41	$511,666.86
		Sum	$2,011,586.25	$107,694.61	$2,119,280.86

UNS GAS, INC.
STAFF'S 6TH SET: TF 6-28c. Customer Deposits

JANUARY 2006 THROUGH DECEMBER 2008
Note: January 2004 - December 2005 Provided in prior rate case.

Acct	Account Title	Date	End Balance
24100	Customer Deposits	JAN-06	($3,127,197.92)
24100	Customer Deposits	FEB-06	($3,126,339.75)
24100	Customer Deposits	MAR-06	($3,125,270.17)
24100	Customer Deposits	APR-06	($3,110,409.09)
24100	Customer Deposits	MAY-06	($3,096,040.90)
24100	Customer Deposits	JUN-06	($3,085,705.60)
24100	Customer Deposits	JUL-06	($3,093,543.92)
24100	Customer Deposits	AUG-06	($3,124,148.28)
24100	Customer Deposits	SEP-06	($3,200,738.94)
24100	Customer Deposits	OCT-06	($3,253,291.68)
24100	Customer Deposits	NOV-06	($3,346,209.35)
24100	Customer Deposits	DEC-06	($3,363,759.99)
24100	Customer Deposits	JAN-07	($3,402,069.30)
24100	Customer Deposits	FEB-07	($3,453,034.24)
24100	Customer Deposits	MAR-07	($3,426,840.79)
24100	Customer Deposits	APR-07	($3,514,869.51)
24100	Customer Deposits	MAY-07	($3,361,558.38)
24100	Customer Deposits	JUN-07	($3,365,274.14)
24100	Customer Deposits	JUL-07	($3,385,228.58)
24100	Customer Deposits	AUG-07	($3,386,825.41)
24100	Customer Deposits	OCT-07	($3,235,273.10)
24100	Customer Deposits	NOV-07	($3,184,534.59)
24100	Customer Deposits	DEC-07	($3,090,471.39)
24100	Customer Deposits	JAN-08	($3,028,603.93)
24100	Customer Deposits	FEB-08	($2,905,315.77)
24100	Customer Deposits	MAR-08	($2,804,224.92)
24100	Customer Deposits	APR-08	($2,737,549.95)
24100	Customer Deposits	MAY-08	($2,676,263.89)
24100	Customer Deposits	JUN-08	($2,609,271.06)
24100	Customer Deposits	JUL-08	($2,609,478.65)
24100	Customer Deposits	AUG-08	($2,611,299.02)
24100	Customer Deposits	SEP-08	($2,590,814.91)
24100	Customer Deposits	OCT-08	($2,589,543.17)
24100	Customer Deposits	NOV-08	($2,680,041.97)
24100	Customer Deposits	DEC-08	($2,687,432.88)

UNS GAS, INC.
STAFF'S 6TH SET: TF 6-28c. Customer Deposits

JANUARY 2006 THROUGH DECEMBER 2008
Note: January 2004 - December 2005 Provided in prior rate case.

Acct	Account Title	Date	End Balance
24100	Customer Deposits	JAN-06	($3,127,197.92)
24100	Customer Deposits	FEB-06	($3,126,339.75)
24100	Customer Deposits	MAR-06	($3,125,270.17)
24100	Customer Deposits	APR-06	($3,110,409.09)
24100	Customer Deposits	MAY-06	($3,096,040.90)
24100	Customer Deposits	JUN-06	($3,085,705.60)
24100	Customer Deposits	JUL-06	($3,093,543.92)
24100	Customer Deposits	AUG-06	($3,124,148.28)
24100	Customer Deposits	SEP-06	($3,200,738.94)
24100	Customer Deposits	OCT-06	($3,253,291.68)
24100	Customer Deposits	NOV-06	($3,346,209.35)
24100	Customer Deposits	DEC-06	($3,363,759.99)
24100	Customer Deposits	JAN-07	($3,402,069.30)
24100	Customer Deposits	FEB-07	($3,453,034.24)
24100	Customer Deposits	MAR-07	($3,426,840.79)
24100	Customer Deposits	APR-07	($3,514,869.51)
24100	Customer Deposits	MAY-07	($3,361,558.38)
24100	Customer Deposits	JUN-07	($3,365,274.14)
24100	Customer Deposits	JUL-07	($3,385,228.58)
24100	Customer Deposits	AUG-07	($3,386,825.41)
24100	Customer Deposits	OCT-07	($3,235,273.10)
24100	Customer Deposits	NOV-07	($3,184,534.59)
24100	Customer Deposits	DEC-07	($3,090,471.39)
24100	Customer Deposits	JAN-08	($3,028,603.93)
24100	Customer Deposits	FEB-08	($2,905,315.77)
24100	Customer Deposits	MAR-08	($2,804,224.92)
24100	Customer Deposits	APR-08	($2,737,549.95)
24100	Customer Deposits	MAY-08	($2,676,263.89)
24100	Customer Deposits	JUN-08	($2,609,271.06)
24100	Customer Deposits	JUL-08	($2,609,478.65)
24100	Customer Deposits	AUG-08	($2,611,299.02)
24100	Customer Deposits	SEP-08	($2,590,814.91)
24100	Customer Deposits	OCT-08	($2,589,543.17)
24100	Customer Deposits	NOV-08	($2,680,041.97)
24100	Customer Deposits	DEC-08	($2,687,432.88)

UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS DOCKET NO. G-04204A-08-0571 May 6, 2009

TF 6.64

List and describe all retirement and incentive programs available to Company officers and employees.

a. Specifically identify the cost of any SERP or similar programs directly charged or allocated.

b. State the cost by program, of each retirement program directly charged or allocated.

RESPONSE:

Incentives: UNS Gas non-union employees participate in UniSource Energy Corporation's ("UniSource") Performance Enhancement Plan ("PEP"). Please see the PDF file TF 6.64(a) (Summary Performance Enhancement Plan), Bates Nos. UNSG(0571)07513 to UNSG(0571)07544, on the enclosed CD for the PEP plan description.

The structure determines eligibility for certain bonus levels by measuring UniSource's performance in three areas:

- Financial performance (UniSource's earnings per share);
- Operational cost containment (UniSource's utility O&M costs); and
- Core business and customer service goals

Levels of achievement in each area are assigned percentage-based "scores," and those scores are combined to calculate the final payout level. The amount made available for bonuses through this formula may range from 15 percent to 150 percent of the targeted payout level.

The financial performance and operational cost containment components each make up 30 percent of the bonus structure, while the core business and customer service goals account for the remaining 40 percent.

The scores from each goal are totaled and then multiplied by the targeted bonus of each employee to determine the total available dollars to be paid out. Targeted bonus percentages, as a percent of base salary, range from 3% to 14% for regular unclassified employees, and 25% to 80% for Managers and Officers. Bonus percentages, as a percent of base salary, are used in the calculation of total available dollars, and actual awards may vary at management's discretion, based on individual employee contribution. If a payout is achieved, employee PEP bonuses will be distributed near the end of the first quarter the following year.

Retirement Programs: UNS Gas Employees are eligible to participate in the Pension Plan for Employees of UniSource Energy Services ("UES"). Please see PDF file TF 6.63(c) (Pension Plan) in response to TF 6.63(c) for the summary plan description. Additionally, UNS Gas Employees are eligible to participate in the Tucson Electric Power Company ("TEP") 401(k) Plan as described below:

401(k) PLAN

TEP's 401(k) Plan takes advantage of Section 401(k) of the Internal Revenue Code and permits employees to voluntarily save from 1/2% to 50% of their pay, before any deduction for state or federal income taxes. UniSource matches, 50 cents on the dollar, up to the first 6% of pay saved in the 401(k) Plan for UNS Gas employees.

Employees' savings and UniSource matching contributions are invested in one or any combination of a selection of professionally managed investment funds at the direction of the employee. Employees are eligible to join the 401(k) Plan upon their date of employment. UniSource matching contributions are fully and immediately vested.

a. UNS Gas is in the process of gathering this information and will provide the response to this data request shortly.

b. UNS Gas is in the process of gathering this information and will provide the response to this data request shortly.

RESPONDENT: Gabrielle Camacho/Dawn Sabers

WITNESS: Dallas Dukes

SUPPLEMENTAL RESPONSE: a. & b. Please see the Excel workbook TF 6.64 on the enclosed CD for expenses for retirement plans requested. The allocation methodology is listed for each expense. For information on the allocation methodology, please see the response to TF 6.35 for our policies on allocations.

RESPONDENT: Linda Joyce

WITNESS: Karen Kissinger

UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS DOCKET NO. G-04204A-08-0571 May 6, 2009

SUPPLEMENTAL RESPONSE: The title of the PDF attachment listed above under the heading "Incentives" is listed incorrectly. The title of the attachment should be TF 6.64 (a) Pension Summary Plan Description. The Bates numbers for this file remain the same, Bates Nos. UNSG(0571)07513 to UNSG(0571)07544.

Additionally, please see the response to TF 6.92 for the Long-Term Incentive Program.

RESPONDENT: Gabrielle Camacho/Dawn Sabers

WITNESS: Dallas Dukes

UNS Gas, Inc.
Retirement & Incentive Plan Expense
For the Test Year Ended 6/30/08
In response to TF6.64a and 6.64b

Plan	Expense per UNSG G/L	Method of Allocation to UNSG
UES Plans:		
UES Pension Plan	$ 705,104	Direct UNSG expense
UES 401K Plan	$ 215,034	Direct UNSG expense
UES PEP Plan	$ 271,655	Direct UNSG expense
Allocations from Other Plans:		
SERP Plan	$ 101,021	Allocated Based on Massachusetts Formula
TEP PEP Plan	$ 125,492	Allocated Based on Massachusetts Formula
Omnibus Plan	$ 242,713	Allocated Based on Massachusetts Formula
Long-Term Incentive Plan	$ -	
Deferred Comp Plan	$ -	
	$ 1,661,019	

SUMMARY PLAN DESCRIPTION OF THE PENSION PLAN FOR EMPLOYEES OF UNISOURCE ENERGY SERVICES

Effective August 11, 2003

DC1 30126334.1

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SUMMARY PLAN DESCRIPTION OF THE PENSION PLAN FOR EMPLOYEES OF UNISOURCE ENERGY SERVICES

Introduction

This document constitutes the Summary Plan Description ("SPD") for the Pension Plan for Employees of Unisource Energy Services (the "Plan"). The Plan is a defined benefit pension plan that Unisource Energy Services ("UES") has adopted for eligible employees. The Plan became effective as of August 11, 2003.

Few goals are of greater long-range importance than providing for a financially secure retirement. That is why Unisource Energy Services ("UES") sponsors this Plan for you and other eligible employees. The Plan is designed to provide you with retirement income for life based on your salary and the years you work for the UES or any other participating company ("Employer"). When your benefits under this Plan are combined with Social Security and your personal savings, it offers valuable financial security for your retirement years.

On August 11, 2003, Tucson Electric Power Company acquired certain assets and liabilities of Citizens Communications Company ("Citizens"). In connection with that acquisition, certain Citizens employees who were active participants in the Citizens Pension Plan became employees of UES. To the extent that those employees will also be entitled to benefits under this Plan, their benefits from this Plan will be integrated with the benefits provided from the Citizens Pension Plan.

Some terms in the summary are technical. See the Glossary in Appendix A starting at page 24 at the back of the SPD for the definition of any capitalized term you do not understand. If you still have questions, please call the Benefits Office for additional help.

You should read this summary closely so you understand how the Plan works. However, because this is a summary, not every provision is described and the description of certain provisions has been simplified. Full details are contained in the Plan document, which is a legal text governing the operation of the Plan. Copies of the Plan document are available to review in the Benefits Office during regular business hours. If you have any questions, contact the Plan Administrator. This SPD does not interpret, extend or change the Plan in any way. If there are any inconsistencies between this SPD and the Plan document, the provisions of the Plan document will govern your rights and benefits.

Eligibility and Enrollment

When Are You Eligible to Participate in this Plan?

Former Citizens Employees. If you were an active participant in the Citizens Pension Plan on August 10, 2003 -- the day before Citizens was acquired, you automatically became a Participant in this Plan as of August 11, 2003, if on that date or immediately after the end of a Permitted Leave, you (a) were employed by UES in an eligible class of Employees and (b) earned at least one "Hour of Service" (as defined below).

New Employees. You will become a Participant on the first day of the month on or after the day you become an Eligible Employee. You are an "Eligible Employee" if :

- UES has classified you as a common law employee of UES;
- you are at least age 21; and
- you have earned one year of Eligibility Service, which is a twelve-month period, beginning with your date of hire (or an anniversary of your date of hire) in which you are credited with at least 1,000 Hours of Service.

You are **not** in the class of employees eligible to participate in the Plan if:

- you provide services to UES as an independent contractor or consultant, or pursuant to an employee leasing agreement, or UES has classified you as a leased employee or as contract labor; or
- you are a collective bargaining employee, and your agreement does not specifically provide for your participation in the Plan; or
- you are a non-resident alien.

Defining Hours of Service. An Hour of Service is each hour that you actually work for UES or an affiliated employer. You also receive an Hour of Service for each regularly scheduled work hour that you do not work, but are paid or entitled to be paid due to an approved leave of absence, vacation, illness, jury duty, holiday or disability. However, you will not receive more than 501 hours of service for any single continuous period during which you perform no duties, and you cannot receive double credit for the same period of service.

Hours of Service are also credited for each hour for which back pay has either been paid, awarded or agreed to by a participating company (to the extent not already counted above).

If you are a former Citizens employee who was actively participating in the Citizens Pension Plan on August 10, 2003, your Hours of Service will include any hours credited to you under the terms of the Citizens Pension Plan, taking into account for this purpose the provisions relating to disregarding service due to a period of severance.

Rehired Employees. If you previously worked for UES and have been rehired as an Employee, your eligibility to participate in the Plan and the date you will be considered to be a Participant will depend on several factors, including (1) your years of employment with UES when you left; and (2) the length of time you were gone.

If you are not an Eligible Employee when you are rehired, you will become a Participant in accordance with the eligibility rules that apply for new Employees (described in the prior section).

If you are an Eligible Employee when you are rehired, you will become a Participant as follows:

- If you are gone for less than 12 consecutive months, you will become a Participant as of your date of rehire.

- If you are gone for 12 or more consecutive months, you must earn at least one year of Eligibility Service after your rehire before you will become a Participant. Upon completing a year of Eligibility Service, you will become a Participant effective on your date of rehire.

- If you did not have a vested interest when you left employment and you are gone for 60 or more consecutive months, you will be treated as a new Employee for purposes of reentering the Plan.

The rules regarding participation and credited service upon rehire are quite complex. If you think they may apply to you, please contact the Benefits Office for more detail.

Service with an affiliated employer. If you work for Tucson Electric Power Company or another affiliate which is part of the same corporate group as UES, you will continue to be credited with Hours of Service under the Plan. However, you will not be eligible to become a Participant unless you are employed by UES, and your service with the non-participating company will not count toward increasing your benefit.

Once You Are Eligible to Participate, How Do You Enroll?

Enrollment in the Plan is automatic. You do not have to complete an enrollment form in order to participate. UES's Benefit Office will notify you when you become a Participant in the Plan.

Who Pays For the Plan?

You do not have to contribute toward the cost of your pension benefits. UES contributes the funds to provide for the payment of benefits under the Plan, and those funds are held in trust.

Benefits Payable under the Plan

Plan Benefits At a Glance

The Plan Provides ...	When ...
Normal retirement benefit	At age 65.
Early retirement benefit	At age 55 if you have at least five years of Vesting Service.
Postponed retirement benefit	When you actually retire after age 65.
Benefits at termination of employment	After five years of Vesting Service.
Retirement income to your spouse	If you die after vesting but before benefits start.

Normal Retirement Benefit

You are eligible to retire with full benefits upon reaching your Normal Retirement Date. This is the first day of the month coinciding with or next following your 65th birthday. Your retirement benefit is calculated on the basis of the following:

- Your "Average Compensation,"
- Your "Average Covered Compensation," and
- Your years of "Benefit Service" up to 35 years.

Each of these terms is discussed below. In addition, if you were an active participant in the Citizens Pension Plan on August 10, 2003, and began participation in this Plan on August 11, 2003, your retirement benefit is reduced by the benefit payable to you from the Citizens Pension Plan. Here is the basic benefit formula that is used for calculating your normal retirement benefit when you retire on or after age 65:

Basic Benefit Formula at Normal Retirement Date
1.3% of your Average Compensation
PLUS
0.7% of the excess of your Average Compensation over your Average Covered Compensation
MULTIPLIED BY
Your years of Benefit Service at retirement, up to 35 years
MINUS (for certain former Citizens employees)
The amount of benefit payable to you from the Citizens Pension Plan

For former Citizens employees who began participation in this Plan on August 11, 2003, note that your Average Compensation and Benefit Service with Citizens is counted in calculating your benefits. Your compensation and service with Citizens is determined according to the provisions of the Citizens Pension Plan (as in effect on August 10, 2003, or your earlier termination), and is counted even if your benefit was frozen as of February 1, 2003.

Here are the important terms you need to know to calculate your retirement benefit from the Plan:

Average Compensation. Your Average Compensation is your average monthly basic earnings for the 60 consecutive months of highest pay during the last 120 months of your Benefit Service. If you have less than 60 months of Benefit Service, Average Compensation will be based on the entire period of your service. For the purpose of determining whether months are consecutive, any month during which you have no Benefit Service will be ignored.

Here is an example. Assume your salary is set annually, so your monthly basic earnings are consistent throughout the year:

Year	Earnings	Year	Earnings
2001	$3,083.33	2006	$3,416.67*
2002	$3,166.67	2007	$3,750*
2003	$3,250	2008	$3,916.67*
2004	$3,583.33	2009	$4,083.33*
2005	$3,333.33*	2010 (6 months to 7/1)	$4,666.67*

*Your 60 consecutive months of highest pay are from July 1, 2005 through June 30, 2010. Your average monthly earnings are $3,833.

"Monthly basic earnings" means your monthly rate of base salary or wages paid to you, determined as of the first day of the month. If you are not compensated at a monthly rate, your monthly rate will be determined as 1/12th of your annual rate. Items of compensation other than base salary or wages, such as overtime pay, special remuneration and employer contributions to any employee benefit plan, are excluded from monthly basic earnings.

The following rules apply to the compensation used to determine Average Compensation:

- Compensation considered in any year cannot exceed $200,000. This amount changes based on IRS rules in effect from time to time.

- Compensation includes amounts you elect to have UES contribute on a pre-tax basis to a 401(k) plan, health plan or flexible spending account. However, non-qualified deferred compensation is not included.

Average Covered Compensation. This is the average of the annual Social Security wage bases on which you and your employer pay Social Security taxes during a 35-year period; it changes from year to year based on cost-of-living adjustments to the Social Security taxable wage base. This 35-year period ends on the last day of the calendar year in which you reach your Social Security retirement age. Average Covered Compensation is based on the Social Security law in effect on January 1, 1977.

Benefit Service. Your Benefit Service is all time (including any approved leaves of absence) beginning on the date you began working for UES and ending on your "Severance from Service" date. You have a "Severance from Service" when your employment terminates for any reason, including quit, involuntary termination, retirement or death. In addition, you have a Severance from Service on the first anniversary of a leave of absence, other than a leave due to (a) pregnancy, birth of a child, placement of a child with you in connection with adoption of the child or caring for a child immediately following birth or adoption or (b) any other protected leave under the Family and Medical Leave Act of 1993. You will have a Severance from Service no later than the second anniversary of the beginning of such a Medical or Family Leave (unless you earlier terminate due to quit, involuntary termination, etc.).

The following periods of service, however, are not included in your Benefit Service:

- any period before you became a Participant in the Plan;
- any Period of Severance, even if it is less than one year. A Period of Severance means the time beginning on your last day of work and ending on the date you are re-employed; and
- any period in which you are ineligible to participate in the Plan (for example, because you are employed by a non-participating affiliate).

If you are not Vested in your benefits when you leave employment or otherwise have a Severance from Service and are later rehired, you can lose credit for your prior Benefit Service. This will happen if:

- you have a period of severance of at least 60 consecutive months; or
- you have a period of severance of at least 12 consecutive months, and you do not earn at least 12 months of service after your reemployment with UES or an affiliated employer.

If you are a Part-Time Employee, your Benefit Service will be computed on the basis that 200 Hours of Service with UES is one-tenth (1/10) of a year of Benefit Service. However, no more than one year of Benefit Service will be credited in any Plan Year. "Part-Time Employee" means an employee who is employed and compensated for 28 hours per week or less.

If you were an active participant in the Citizens Pension Plan on August 10, 2003 and became a participant in this Plan on August 11, your Benefit Service will include the Benefit Service credited to you under the terms of the Citizens Pension Plan for purposes of calculating your benefit under the Plan , and the amount of offset of your benefit attributable to your Citizens Pension Plan benefit. Your Citizens' Benefit Service is also used in determining whether you have earned 35 years of Benefit Service. Note that Benefit Service that is disregarded under the Citizens Pension Plan because of a break in your service is similarly disregarded under this Plan.

An Example of the Normal Retirement Benefit Calculation – Assume you decide to retire in 2004 at age 65 with 30 years of Benefit Service. Also assume your Average Compensation is $4,200 per month. Based on your retirement date, your Annual Covered Compensation is $43,992, or $3,666 a month. Therefore, your Average Compensation over Average Covered Compensation is $534. Here's how your normal retirement benefit under this Plan is determined:

Normal Retirement Benefit Calculation Under this Plan

1.3% of your Average Compensation = .013 x $4,200 (A)	$54.60
Plus 0.7% of the excess of Average Compensation over Average Covered Compensation = .007 x $534 (B)	+ $3.74
Total of the two calculations above (A + B = C)	$58.34
Multiplied by the aggregate of your Benefit Service under the Citizens Pension Plan and this Plan (up to 35 years) (S)	x 30
Normal Straight Life retirement benefit (C x S) =	$1,750.20

In this example, your normal Retirement Benefit would be $1,750.20. This is the amount payable to you each month for life beginning at age 65. Keep in mind that your monthly payment will be adjusted if you elect to receive it in any other payment form - for example, in monthly payments over your lifetime and the lifetime of your spouse.

If you are a former Citizens employee who was an active participant in the Citizens Pension Plan on August 10, 2003 and began participation in this Plan on August 11, 2003, any amount payable to you under the Citizens Pension Plan will be subtracted from the amount payable under this Plan. For purposes of the prior example, assume that 29 of the 30 years of Benefit Service were with Citizens, and one year of Benefit Service was under this Plan. Also assume that your Average Compensation under the Prior Plan was $4,100, and Annual Covered Compensation was $3,664 in 2003. Therefore, your Average Compensation over Average Covered Compensation is $436.

Based on these assumptions, your normal Retirement Benefit under the Citizens Pension Plan would be:

$1,634.15 per month on a Straight Life basis. As a result, that amount will be deducted from the amount you will receive from this Plan. Accordingly, you will receive $1,634.15 per month from the Citizens Pension Plan and $116.05 per month from this Plan, for a total retirement benefit of $1,750.20 per month on a Straight Life basis.

Early Retirement Benefit

You may retire as early as the first day of the month coinciding with or next following your 55th birthday, as long as you have completed five years of Vesting Service. For the definition of Vesting Service, see the discussion entitled "How your Vesting Service is Determined," later in the SPD.

Your early Retirement Benefit is your Accrued Normal Retirement Benefit as of the date your employment ends, multiplied by the early retirement fraction described below. Your Accrued Normal Retirement Benefit is the benefit you have earned through the date you stop working (under the normal retirement formula above) but using the Benefit Service you would have had if you had continued working until your Normal Retirement Date (up to 35). This "projected" retirement benefit is then multiplied by the ratio of your actual Benefit Service to the Benefit Service you would have if you continued working to your Normal Retirement Date.

Formula for the Early Retirement Fraction
Your actual Benefit Service as of the date your employment terminates (determined without regard to the 35 year limit)
DIVIDED BY
Your projected Benefit Service as if you had continued working until your Normal Retirement Date (determined without regard to the 35 year limit)

As noted above, your benefit will be subject to a second reduction if you begin receiving payments before your Normal Retirement Date. Your benefit will be reduced by five-twelfths (5/12) of one percent (1%) for each full month for which you receive distribution of your benefits before you turn age 65. This reduction is made because you will be receiving payments over a longer period of time. The reduction is calculated monthly; however, the schedule below gives you an idea of the reduction factors that would apply for selected ages:

Early Retirement Benefit Reduction Schedule

Age at Retirement	Reduction Factor (0.417% multiplied by pre-age 65 months)	Benefit as a % of Normal Retirement Benefit
65	0%	100%
64	5%	95%
63	10%	90%
62	15%	85%
61	20%	80%
60	25%	75%
59	30%	70%
58	35%	65%
57	40%	60%
56	45%	55%
55	50%	50%

If you retire in the middle of a year, the reduction is interpolated based on the first of the month in which your benefit begins.

An Example of the Early Retirement Benefit Calculation -- Assume as in the prior example that you decide to retire in 2004, but you are age 60 with 30 years of Benefit Service. Also assume your Average Compensation is the same, $4,200 per month. Based on your 2004 retirement date, your Annual Covered Compensation is $43,992, or $3,666 per month, and your Average Compensation over Average Covered Compensation is $534. Based on these assumptions, the early Retirement Benefit would be calculated as follows:

Early Retirement Benefit Calculation Under this Plan

1.3% of your Average Compensation = .013 x $4,200 (A)	$54.60
Plus 0.7% of the excess of Average Compensation over Average Covered Compensation = .007 x $534 (B)	+ $3.74
Total of the two calculations above (A + B = C)	$58.34
Multiplied by your Benefit Service projected to normal retirement date (up to 35 years) (S)	x 35
Normal straight life retirement benefit** (C x S) =	$2,041.90
Reduced by the Early Retirement Fraction of 30/35	x .857143
Monthly adjusted straight life benefit payable at age 65	$1,750.20

** Note that this amount will be reduced by amounts payable to you under the Citizens Pension Plan.

As you can see from the calculation, if you leave UES before your Normal Retirement Age, your early retirement benefit expressed as a straight life annuity benefit beginning at age 65 is $1,750.20. If you elect to receive payments before your 65th birthday, your benefit will be reduced by five-twelfths (5/12) of one percent (1%) for each month that you receive distribution of your benefits before you turn 65. In the example used above, if you elect to receive payments immediately after your 60th birthday, you will receive your benefits 60 months before your 65th birthday, so the reduction is 25%. Accordingly, you would receive 75% of $1,750.20, or $1,312.65 each month, commencing as of your 60th birthday. Also keep in mind that your monthly payment will be adjusted if you elect to receive it in any other payment form - for example, in monthly payments over your lifetime and the lifetime of your spouse.

Important: If you plan to retire early and you want to receive your benefits beginning with the first day of the month after your Termination of Employment, you should contact the Benefits Office at least 120 days in advance. Your retirement election must be made within the 90-day period ending on the date you want your retirement benefits to begin.

Postponed Retirement Benefit. You will continue to earn retirement benefits if you work beyond your Normal Retirement Date. In that case, you will receive a retirement benefit beginning on the first day of the month after you retire. Your postponed benefit is determined using the Normal Retirement Benefit formula above, based on your Average Compensation and Benefit Service (not in excess of 35 years) as of the date you retire.

Disability Retirement Benefit. If you are a Participant with five or more years of Vesting Service and you become Permanently Disabled while you are employed by UES, you will be entitled to a disability retirement benefit.

Definition of Permanent Disability and Disability Retirement Date

For purposes of this Plan, you will be considered to have a "Permanent Disability" (or be "Permanently Disabled") if you are determined to be disabled under the UES Long-Term Disability Plan ("LTD Plan"), and the disability continues for at least six (6) consecutive months.

Your Disability Retirement Date is the date that the Committee determines your absence due to the Permanent Disability began.

While you are Permanently Disabled, you will continue to be credited with Benefit Service and Vesting Service until the earliest of:

(1) the later of your Normal Retirement Date or the fifth anniversary of your Disability Retirement Date;

(2) the date you refuse to submit to a medical examination as required to determine whether the Permanent Disability still exists;

(3) the date you cease to be Permanently Disabled;

(4) the date of your death;

(5) the date your LTD Plan benefits cease; or

(6) the date your Retirement Benefit begins.

You can elect to begin your Retirement Benefits when you are eligible for a Normal or Early Retirement Benefit. Your disability retirement benefit will be calculated using the applicable benefit formula (based on whether you will be receiving an early or normal Retirement Benefit), based on your Average Compensation as of your Disability Retirement Date and the Benefit Service credited to you above. Remember that continuing service credits end when you elect to retire.

If you are a Part-Time Employee on your Disability Retirement Date, your Benefit Service will be credited at a rate of one-twentieth (1/20) of a year of Benefit Service for each month of Permanent Disability, with a maximum of six months of Benefit Service credited in any Plan Year.

Keep in mind that if you elect to receive a benefit before your Normal Retirement Age, the Plan's early retirement factors will apply.

Vesting and Forfeiture of Benefits at Termination of Employment

Vesting refers to the extent to which you have a nonforfeitable right to your retirement benefit when you leave UES. If you are credited with five or more Years of Vesting Service, your right to your retirement benefits are fully or 100% vested, and you are entitled to all of the benefits you earned under the Plan when you retire or otherwise leave UES. In addition, regardless of your Vesting Service, your benefits are 100% vested at your Normal Retirement Age if you are actively employed by UES.

How is Vesting Service Determined?

Vesting Service is equal to your aggregate Periods of Service and any periods that are required by law to be credited to you for periods of military service. A Period of Service begins on your Employment Commencement Date and ends on your Severance from Service Date, and includes Periods of Severance under 12 months. The following periods are not counted in determining Vesting Service:

- Any Periods of Severance of 12 months or more;
- Any Periods of Service before a Period of Severance that is 60 consecutive months or more, if benefits were not vested;
- Any Periods of Service before a Period of Severance of at least 12 consecutive months unless you are credited with a one year Period of Service after that Period of Severance; and
- Any Periods of Service prior to your 18th birthday.

A Period of Severance commences on the date your employment terminates, and ends on any subsequent reemployment date. A Period of Severance will not include:

- Credited Leave, which is defined as any leave of absence (1) due to illness or injury (not otherwise required to be credited to you under the Family and Medical Leave Act); or (2) for further education; or Government service as determined by UES;
- Any leave of absence to enter the Armed Forces of the United States (1) through the operation of a compulsory military service law; (2) during a period of declared national emergency; or (3) pursuant to a leave of absence granted by UES, as long as you return to the service of UES within 90 days (or such longer period as may be required by law) after your discharge or release from active duty, or within the period for which leave of absence was granted by UES; or
- Any absence from work due to a leave under the Family and Medical Leave Act.

If you began participation in this Plan or with an affiliated employer on August 11, 2003, your Vesting Service includes the Vesting Service credited to you under the terms of the Citizens Pension Plan, including its provisions disregarding service due to a Period of Severance.

Effect of Termination of Employment

If your employment terminates before your Early Retirement Age (age 55 with 5 or more years of Vesting Service), you will be entitled to receive benefits only if you have at least 5 years of Vesting Service when you leave. If you leave employment before you are fully vested in your benefits, you will forfeit your unvested pension benefits.

Your Termination of Employment Benefits are calculated in the same way as Early Retirement Benefits (described above), using your Benefit and Vesting Service as of the date of Termination of Employment. Your benefits can begin as early as the first of the month on or after your 55th birthday. Remember, benefits will be actuarially reduced if you begin payment before your Normal Retirement Date at a rate of $5/12^{ths}$ of 1% per month.

If the Actuarial Equivalent present value of your benefits when you leave is $5,000 or less, you will automatically receive your benefit in a single lump sum (which you may elect to have rolled over to a new plan). In contrast, if your benefits exceed $5,000, you will have a choice of the form in which you receive those benefits (see the section below entitled "How Benefits are Paid").

Be sure to notify UES if you have a change in address. This way, UES will be able to contact you when you become eligible for a distribution of your vested benefits.

Any benefit that is not vested will be deemed cashed out on the date you incur a Period of Severance of 12 consecutive months. If you are rehired and earn a Year of Service before you have a five (5) year Period of Severance, your benefit will be restored.

Transfers to Another Employer. If you transfer to an affiliated employer that has not adopted this Plan, you will cease to accrue additional benefits under this Plan.

Re-employment After Retirement.

If you are rehired by UES after you have begun receiving retirement benefits from this Plan before Normal Retirement Date (your sixty-fifth (65) birthday), your benefits will be suspended until you subsequently retire. When you subsequently retire, your benefit will be based upon your Average Compensation and Benefit Service at your subsequent retirement date, reduced by the actuarial value of prior payments you <u>received</u>. If you received a lump sum payment of your vested benefit when you previously left employment, your prior Benefit Service will be disregarded for all purposes of the Plan.

If you are rehired (or continue to be employed by UES) after your sixty-fifth (65th) birthday, your benefits will be suspended for each month in which you are credited with forty (40) or more Hours of Service. You must notify UES in order to resume benefits after you stop being so employed. Your benefits will resume no later than the third month after you stop being so employed, assuming you have given the required notice to UES.

The details regarding the impact of rehire upon the payment, the amount and form of benefits under the Plan are extensive. If you are thinking about returning to work with

UES after commencing your benefits under the Plan, please contact the Plan Administrator for the specific rules that will apply to your situation.

How Benefits are Paid

The Plan allows you to receive your retirement benefits in a variety of ways. You choose the method that best fits your personal financial needs.

Forms of Benefits. If the Actuarial Equivalent present value of your vested benefit exceeds $5,000, you may elect to receive your benefits under several different payment options:

- Life Annuity: This option provides monthly benefits to you for life. When you die, payments end. No income will be paid to anyone else.

- Life Annuity with a five or ten-year certain feature: The 5-year or 10-year life annuity pays reduced monthly benefits to you for life, with guaranteed payments for a period of 60 or 120 months, as you elect. If you die within the guaranteed period, your designated Beneficiary will receive your monthly benefit for the remainder of the period. If you receive monthly benefits for the full guaranteed period during your lifetime, no benefits will be paid after you die. The amount by which your benefit is reduced depends on the option you choose and your age. If your Beneficiary dies before you, you may designate a new Beneficiary.

- 33 1/3, 50%, 66 2/3%, 75%, or 100% Joint and Survivor Annuity Options: These options provide a reduced joint and survivor annuity. A joint and survivor annuity provides a monthly benefit to you for your lifetime. After your death, your Beneficiary will receive the percentage elected of your monthly benefit for the remainder of his or her lifetime. The monthly benefit you receive will be less than a single life annuity because it will be paid over two lifetimes - yours and your Beneficiary's. The amount of the reduction depends on your age and the age of your Beneficiary when benefit payments begin. If your Beneficiary dies before you, you cannot name another Beneficiary, and your payment level will not increase. Benefits end upon your death.

- Voluntary lump-sum distribution: If your vested benefit exceeds $5,000, this option provides a lump-sum distribution. The amount of the lump sum is the Actuarial Equivalent present value of your vested benefit payable on your Annuity Starting Date.

If the Actuarial Equivalent present value of your vested benefit is $5,000 or less, you will automatically receive your benefit in a single lump sum. This applies to both single and married employees. Thereafter, you will not be entitled to any monthly benefit.

Special Rules for Married Participants. If you are married on your Annuity Starting Date, you must receive distribution of your vested benefit in the form of a 50% (or greater) Joint and Survivor Annuity with your spouse as your Beneficiary, unless you and your spouse elect to waive this form of distribution. Your spouse's election must be witnessed by a notary public or the Plan Administrator during the 90-day period ending on your Annuity Starting Date. Your election must state the optional form of benefit that you would like distributed and the time of the distribution, and must designate any non-spouse Beneficiary, including contingent Beneficiaries, which cannot be changed without your spouse's consent (if applicable). A spouse's consent to the waiver, once given, may not be revoked. You may revoke the waiver of a Joint and Survivor Annuity without your spouse's consent at any time prior to your Annuity Starting Date (and if so desired, waive it again before that date so long as the requirements for the waiver are satisfied).

Electing a Payment Method. You must elect the form of payment during the 90-day period preceding your Annuity Starting Date. This election may not be changed after your Annuity Starting Date. Remember to contact us 120 days in advance. As you approach retirement age, you will receive more specific information about your benefit options and payment amounts.

If no election of method of distribution is made and you are single, you will be deemed to have elected a straight life annuity with no ancillary benefits. If you are married, you will be deemed to have selected a 50% Joint and Survivor Annuity with your spouse as the Beneficiary.

Keep in mind that you may be asked to provide copies of your birth certificate, applicable spouse birth certificate and marriage license, and may be asked to provide proof of a divorce or spouse death certificate.

Survivor Benefits

If You Die Before Retirement Benefits Begin. If you die before retirement benefits begin, have a vested benefit in the Plan, and are survived by a spouse to whom you have been married for at least one (1) year at the time of your death, your spouse will be eligible to receive a Qualified Preretirement Survivor Annuity. Your spouse is eligible for this benefit even if you are no longer working when you die. This benefit will be paid to your spouse in the form of an annuity for your spouse's life. If the Actuarial Equivalent present value of the Qualified Preretirement Survivor Annuity does not exceed $5,000, the benefit will be paid as a lump sum.

Amount of Benefit. The amount of the annuity your surviving spouse can receive from the plan is the survivor benefit the spouse would have received if you (1) terminated employment on your date of death or earlier termination date, (2) survived to your earliest retirement age under the plan (or, if later, your actual date of death), (3) elected a 50% Qualified Joint and Survivor Annuity at that time, and then (4) died immediately after you began receiving payments. Note that the benefit is actuarially adjusted to the extent that payments begin before you would have attained age of 65.

When Payments Begin. The distribution to your spouse will begin on the earliest of:

a) the first day of the month following your death, if your death occurs after your Normal Retirement Age;

b) the first day of the month following your Normal Retirement Age if your death occurs prior to that time, unless your spouse elects to receive the benefit before your Normal Retirement Age (but not earlier than the date you would have attained your Early Retirement Date had you survived); and

c) if you die before your Normal Retirement Age, and the Actuarial Equivalent present value of the Preretirement Death Benefit does not exceed $5,000, the first day of the month following your death.

If you die before your Normal Retirement Age, and the present value of your Preretirement Death Benefit exceeds $5,000, your spouse may elect to have distribution of the benefit begin on the first day of any month following the election, but not earlier than your Early Retirement Date or after your Normal Retirement Age.

Special Circumstances

- If you are married, and (a) you give the Committee written notice of your election to commence your retirement benefits on a specific date, or your retirement benefit is to commence on or after your Normal Retirement Date or after you reach age 70½ in the absence of such election, and (b) within 90 days prior to the benefit commencement date, you elect a joint and survivor annuity form of payment with your spouse to receive more than 50% of the amount payable, then your surviving spouse's annuity will be based on the larger amount payable under the joint and survivor annuity.

- If you are married, and (a) you die while employed or while on Permanent Disability after having elected to retire within 90 days of such election and to commence your retirement benefit in the form of a lump-sum payment, and (b) your death occurs prior to the benefit commencement date, a lump-sum payment in the same amount will be payable to your spouse on the date the payment would have been made to you had you lived. In order to receive this lump-sum payment, your spouse must, within 60 days after the date of your death, waive the Preretirement Death Benefit that would otherwise be payable.

If You Die After Retirement Benefits Begin. If you die after you have started to receive your retirement benefit, payments will continue only if you elected a payment form that provides for a survivor benefit to be paid to your designated Beneficiary. You need to understand that a single life annuity provides monthly benefits to you for life. If you elect to have your retirement benefit paid to you in that form, payments end when you die. No income will be paid to anyone else.

No benefit is paid under the plan if you die before retirement benefits begin and you are not survived by a legal spouse.

Taxes and Your Benefits

You are responsible for paying applicable taxes on your benefit when you receive it. Under current tax law, your retirement benefit is not taxable while it remains in the Plan. When you (or your Beneficiary) receive a distribution from the Plan, you are responsible for paying applicable income taxes. If a lump sum payment is made, you may also owe a 10% penalty tax if your retirement benefits are paid to you before age 59½ and you terminate employment before the beginning of the year in which you reach age 55.

In general, you can defer paying taxes if you elect to "rollover" your lump sum payout (that is, have it transferred directly) to a plan that will accept rollovers ("Eligible Retirement Plan"), such as a 401(k) plan, a section 457 government plan, or a section 403(b) annuity, or to a traditional or "conduit" individual retirement account ("IRA"). However, certain types of payments generally cannot be rolled over:

- Payments Spread Over Long Periods: Annuity payments cannot be rolled over because they are part of a series of equal (or almost equal) payments that are made at least once a year and will last for your lifetime or for more than ten (10) years.

- Required Minimum Payments: Beginning in the year you reach age 70½ or retire, whichever is later, a certain portion of your payment cannot be rolled over because it is a required minimum payment that must be paid to you.

If you do not elect a direct rollover of the entire lump sum distribution, the Plan is generally required to withhold 20% of the taxable portion of the amount distributed. You will receive additional information on the rollover or direct transfer option when you terminate employment and are ready to receive a distribution.

If you receive payment of your benefit in the form of an annuity (fixed payments for life), you may elect whether or not to have taxes withheld. If you do not make any election, federal income tax will be withheld automatically. Withholding is applied as if the payments were wages. If you elect not to have withholding apply, or even if you do elect withholding, you may still owe taxes on the payments. You are responsible for payment of any taxes associated with the payments.

Tax laws change from time to time, and the tax impact of receiving payments from the Plan will vary with your individual situation. Because UES cannot give tax advice or counsel, you should consult a professional tax advisor or financial expert for specific advice about your circumstances.

Social Security Benefits

Throughout your working career, both you and UES contribute toward your Social Security benefits through payroll taxes. These benefits are in addition to your benefits under the Plan and provide you with an important source of retirement income. ***You will not receive Social Security benefits automatically. You must apply for them.***

If you were born on or before January 1, 1938, your full Social Security benefits can begin at age 65. If you were born later than that date, your full Social Security benefits can begin between the ages of 65 and 67, depending on your birth date. You can consult the chart at the Social Security Administration's website on the Internet at http://www.ssa.gov/retirechartred.htm for the age when you will be entitled to receive your full benefits. You may begin receiving reduced Social Security benefits at age 62.

If you are married, your spouse also is entitled to receive Social Security benefits in an amount based on your pay or his or her pay – whichever produces the greater benefit.

Additional information about your Social Security benefits and how to apply for them is available through SSA's website at http://www.ssa.gov, or you can contact your local Social Security office. The national toll-free number for Social Security currently is 1-800-772-1213.

Plan Administration

The Plan is administered by a Committee appointed by the President of Tucson Electric Power Company. The Committee consists of at least three members, and its functions include resolving claims for benefits and interpreting and construing the terms of the Plan. The Committee has absolute and exclusive authority to interpret the provisions of the Plan in its discretion. The Committee will appoint a Plan Administrator who will maintain Plan records, and make appropriate reports and disclosures required by ERISA. A Trustee will be appointed to manage and control the trust fund and its assets.

How to Apply for Benefits -- Claims Procedure

To receive benefits under the Plan, you must apply to the Benefit Claims Committee. This section describes how to file a claim and an appeal.

Filing a Claim. There are specific procedures for filing claims and settling disputes. The Benefit Claims Committee can explain these to you. To receive benefits from the Plan, you or your Beneficiary must submit a request in writing to the Benefit Claims Committee. You should contact the Committee at least 90 days before you want to begin receiving your benefits.

If Your Claim is Wholly or Partially Denied. If you file a claim for benefits under the Plan and your claim is denied in whole or in part, you will be notified in writing. The notification will include:

- The reason for the denial;
- The specific Plan provisions on which the denial was based;
- A description of any additional information needed to process your claim; and
- An explanation of the claim review procedure.

Ordinarily you will receive this written notice within 30 days after your claim is filed.

If you disagree with the decision, you have a right to request a review of the denial of your claim. To do so, you, your Beneficiary, or your authorized representative must submit a written request to the Benefit Claims Committee within 60 days of receiving the notice of denial. You may review relevant documents or records and submit your comments in writing. You, your Beneficiary, or your authorized representative will have the right to review all pertinent Plan documents.

You will receive a written decision on your request for review within 60 days of the date the Benefit Claims Committee receives your request unless special circumstances, such as the need to hold a hearing, require an extension of time, in which case the 60-day period shall be extended to 120 days and you will be notified of the extension. You will be notified in writing of the final decision, and this decision shall include the specific reasons for the decision, referring to Plan provisions that set forth those reasons.

If you receive a final denial regarding your claim for benefits, you have certain rights under the law. For more information, see the section entitled "ERISA Rights" on page 21.

Additional Information About the Plan

The following is general information about the Plan, certain federal laws, and your rights under the Plan. Please read this section carefully, paying particular attention to how the Plan is governed by federal law.

Internal Revenue Service (IRS) Limits. Government regulations put a cap on the amount of income an employee may receive under a qualified pension plan. For example, Federal law limits the amount that can be considered as compensation for Plan purposes each year. In addition, the IRS sets certain limitations on the amount that employees can receive from plans like the Plan.

The IRS may adjust these limits from time to time to reflect changes in the cost of living. You will be notified if you are affected by these limits.

Non-assignment of Benefits and Qualified Domestic Relations Orders. You cannot assign the benefits payable to you to another person. One exception is that benefits will be paid according to a valid Qualified Domestic Relations Order (QDRO).

A QDRO is an order from a state court that meets certain legal specifications and directs the Plan to pay all or a portion of a Participant's benefits to a spouse, former spouse, or dependent child.

You will be notified immediately if an attempt is made to assign your benefits through a court order. The Committee is responsible for determining whether or not the order is qualified, and has adopted procedures governing QDROs. You can obtain a copy of those procedures, without charge, by contacting the Benefits Office.

Payment to Minors and Incompetents. If anyone entitled to income from the Plan is a minor or is judged to be physically or mentally incompetent, the Committee may pay the income to someone else for the benefit of the recipient (to a legal guardian, for example).

You may execute a form referred to as a "power of attorney" that authorizes another person or entity to act on your behalf if due to illness or incapacity, you are unable to do so yourself. You must specifically mention in the power of attorney that you are authorizing that person or entity to act on your behalf with regard to your benefits under this Plan. Please contact the Benefits Office for additional information regarding this issue.

Top-Heavy Rules. Under current tax law, if a plan provides more than 60% of its benefits to "key" employees, that plan is considered to be "top heavy." Both "top-heavy" and "key" employees are terms defined under the Code.

At present, the Plan is not top-heavy. In the unlikely event that it becomes top-heavy, you will be notified, your benefits may be adjusted, and your vesting may be accelerated to keep the Plan qualified under IRS regulations.

Continuance of the Plan

Amendment or Termination of the Plan. UES reserves the right to amend the Plan at any time and for any reason by action of the President of Tucson Electric Power Company ("TEP"). UES may also terminate the plan at any time and for any reason by action of the Board of Directors of TEP.

If UES terminates the plan for any reason, the assets in the Plan will be used for the exclusive benefit of Plan Participants and their beneficiaries. Any funds that remain after all benefits are paid to Participants will revert to UES. If you are affected by the termination, you will become 100% vested in your retirement benefit under the Plan, to the extent the benefit is funded.

Plan Insurance. The benefits under this Plan are insured by the Pension Benefit Guaranty Corporation ("PBGC"), a federal insurance agency. If the Plan terminates (ends) without enough money to pay all benefits, the PBGC will step in to administer the Plan and pay retirement benefits. Most people will receive all of the retirement benefits they would have received under the Plan, but some people may lose certain benefits.

The PBGC guarantee generally covers:

- Normal and Early retirement benefits;
- Disability benefits if you become disabled before the Plan terminates; and
- Certain benefits for your survivors.

The PBGC guarantee does not cover:

- Benefits greater than the maximum guarantee amount set by law for the year in which the Plan terminates;
- Some or all of benefit increases and new benefits based on Plan provisions that have been in place for fewer than 5 years at the time the Plan terminates;
- Benefits that are not vested because you have not worked long enough for UES;
- Benefits for which you have not met all of the requirements at the time the Plan terminates;
- Certain early retirement payments (such as supplemental benefits that stop when you become eligible for Social Security) that result in an early retirement monthly benefit greater than your monthly benefit at the plan's Normal Retirement Age; and
- Non-retirement benefits, such as health insurance, life insurance, certain death benefits, vacation pay and severance pay.

Even if some of your benefits are not guaranteed, you may still receive some of those benefits from the PBGC depending on how much money the Plan has and on how much the PBGC collects from employers. For more information on the PBGC and the benefits it guarantees, ask your Plan Administrator or contact the PBGC's Technical Assistance Division, 1200 K Street, N.W., Suite 930, Washington, D.C. 20005-4026 or call 202-326-4000 (not a toll-free number). TTY/TDD users may call the federal relay service toll-free at 1-800-877-8339 and ask to be connected to 202-326-4000. Additional information about the PBGC's pension insurance program is available through the PBGC's website on the Internet at http://www.pbgc.gov.

ERISA Rights

If you are a Participant in the Plan, you are entitled to certain rights and protections under the Employee Retirement Income Security Act of 1974 ("ERISA"). The following is a summary of those rights:

- You may examine, without charge, all Plan documents, including insurance contracts and copies of all documents filed by the Plan with the U.S. Department of Labor, such as detailed annual reports and Plan descriptions. These documents are available during regular business hours.

- You may obtain copies of all Plan documents by writing to the Plan Administrator. There will be a reasonable charge for duplicating documents.

- Each year you will receive a summary of the Plan's annual financial reports. The Plan Administrator is required by law to furnish you with a copy of this information.

- Upon your written request, you may obtain a statement telling whether you have a right to receive a benefit under the Plan, and if so, the amount of the benefit. If you are not eligible for a benefit, the statement will tell how many more years you have to work to get a right to a benefit. This statement is not required to be given more than once a year. It is provided free of charge.

- If your claim for a benefit is denied in whole or in part, you must receive a written explanation of the reason for the denial. You have the right to have the Plan review and reconsider the claim.

In addition to creating rights for Plan Participants, ERISA imposes duties on the people who are responsible for the operation of employee benefit plans. The people who operate the plan are called "fiduciaries." Fiduciaries have a duty to operate the plan prudently and in the interest of all Plan Participants and Beneficiaries. No one, including UES or any other person, may fire you or otherwise discriminate against you in any way to prevent you from obtaining a benefit or exercising your rights under ERISA.

Under ERISA, there are steps you can take to enforce these rights. For instance, if you make a written request for materials from the Plan and do not receive them within 30 days, you may file suit in federal court. In such a case, the court may require the Plan Administrator to provide the materials and pay you up to $110 a day until you receive the materials, unless the materials were not sent because of reasons beyond the control of the Plan Administrator. If you have a claim for benefits that is denied or ignored, in whole or in part, you may file suit in a state or federal court. In addition, if you disagree with the Plan's decision or lack thereof concerning the qualified status of a domestic relations order, you may file suit in a state or federal court.

If it should happen that the Plan fiduciaries misuse the Plan's money, or if you are discriminated against for asserting your rights, you may seek assistance from the U.S. Department of Labor, or you may file suit in a federal court. The court will decide who should pay court costs and legal fees. If you are successful, the court may order the person you have sued to pay these costs and legal fees. If you lose, the court may order you to pay these costs and fees; for example, if it finds that your claim is frivolous.

If you have any questions about the Plan, you should contact the Plan Administrator. If you have any questions about this statement or about your rights under ERISA, or if you need assistance in obtaining documents from the Plan Administrator, you should contact the nearest Area Office of the Employee Benefits Security Administration, U.S. Department of Labor, listed in your telephone directory or the Division of Technical Assistance and Inquiries, Employee Benefits Security Administration, U.S. Department of Labor, 200 Constitution Avenue, N.W., Washington, D.C. 20210.

Appendix A

Glossary of Terms

Actuarial Equivalent means a benefit or amount that replaces another and has the same value as the benefit or amount it replaces based on the applicable actuarial assumptions and interest rates.

Affiliated Company means UES or any entity that is in the same controlled group or under common control with UES in accordance with the rules defined in the Internal Revenue Code.

Annuity Starting Date generally means the first date as of which your vested retirement benefits or **Preretirement Death Benefits** are to begin, or the date on which your lump sum is paid to you.

Beneficiary means the person or persons who would become eligible to receive any benefits under the Plan in the event of your death.

Benefit Claims Committee means the committee designated to review your request for benefits.

Board means the Board of Directors of Tucson Electric Power Company or its authorized delegate.

Code means the Internal Revenue Code of 1986, as amended from time to time.

Committee means the committee appointed by the Board to administer the Plan.

Credited Leave means any leave of absence due to illness, injury, further education or Government service as determined by the **Committee**. This term includes any leave of absence to join the Armed Forces of the United States in connection with a compulsory military service law, during a period of declared national emergency, or if UES grants other military-related leaves of absence, provided you return to work within 90 days (or such longer periods as may be provided by law) after your discharge or release from active duty in the Armed Forces, or within the period for which your leave of absence was granted by UES.

Eligible Retirement Plan means an individual retirement account, individual retirement annuity, annuity plan, or qualified trust, as defined in the **Code**, that accepts your eligible rollover distribution. In the case of an eligible rollover distribution to a surviving spouse, an **Eligible Retirement Plan** is an individual retirement account or individual retirement annuity.

Employee means any person classified and treated by UES as a common-law employee.

Employer means **UES** and any participating company.

Employment Commencement Date generally means the day you are first credited with an **Hour of Service**, or if you had a **Period of Severance**, the day you are first credited with an **Hour of Service** after the **Period of Severance**.

ERISA is the Employee Retirement Income Security Act of 1974, as amended from time to time.

50% Joint and Survivor Annuity means an annuity for your lifetime with a survivor annuity for the life of your surviving spouse where the survivor annuity is 50% of the amount of the annuity payable during the joint lives of you and your spouse. The joint and survivor annuity is at least the **Actuarial Equivalent** of the most valuable form of benefit under the Plan payable to you on your **Annuity Starting Date**. Note, however, if you were participating in the Citizens Pension Plan on December 31, 1975, and if you were to die before receiving a total of 120 monthly payments, then your survivor will receive the amount that would have been payable to you (as though you had not died), until a total of 120 monthly payments have been made. After the 120th month, the amount of the survivor pension will be 50% of the reduced pension. In addition, the survivor annuity will be payable until a total of 120 monthly payments have been made without regard to whether or not your spouse is living. Any such survivor annuity payable after the death of your spouse will be payable to a **Beneficiary**.

Medical or Family Leave means an Employee's leave of absence from employment with an Affiliated Company because of: (a) pregnancy, birth of the Employee's child, placement of a child with the Employee in connection with adoption of the child or caring for a child immediately following birth or adoption or (b) any other reason that would entitle the Employee to take a leave under the Family and Medical Leave Act of 1993. The Employer shall determine the first and last day of any Medical or Family Leave.

Participant means an **Eligible Employee** who is participating in this Plan.

Period of Service means a period (including any periods of **Credited Leave**) beginning when a **Participant** is credited with an **Hour of Service (Employment Commencement Date)** and ending on the **Participant's Severance from Service Date**. For vesting purposes, **Period of Service** includes any **Period of Severance** under 12 months.

If you became a **Participant** in this **Plan** because you were an active participant in the Citizens Pension Plan on August 10, 2003, a **Period of Service** for any period prior to August 11, 2003, will be determined according to the terms of the **Citizens Pension Plan**, including provisions relating to disregarding service due to a **Period of Severance.**

Period of Severance means the time beginning on your last day of work and ending on the date you are re-employed.

Permanent Disability means total disability by bodily or mental injury or disease as determined by the Committee based on a determination made by the insurer under the Company's long-term disability plan or the Social Security Administration provided:

(a) the Employee has five years of Vesting Service;

(b) the Employee becomes entitled to benefits under the Company's long-term disability plan;

(c) the Employee earns at least one Hour of Service as an active Employee of an Employer after the Effective Date; and

(d) such disability shall have existed for a period of six consecutive calendar months.

Permitted Leave means an approved leave of absence from **UES,** including but not limited to military service, illness, disability, **Medical** or **Family Leave**, educational pursuits, service as a juror, temporary employment with a government agency, or any other leave of absence approved by the participating company.

Plan means the Pension Plan for Employees of Unisource Energy Services.

Plan Year means the calendar year.

Preretirement Death Benefit means the death benefit payable under the Plan to your surviving spouse if you die before your **Annuity Starting Date** and the following additional criteria are met:

- you have a vested benefit in the Plan, and
- you have been married to your spouse for at least one (1) year at the time of your death.

Qualified Preretirement Survivor Annuity means an immediate survivor annuity for the life of your spouse, equal to:

- If you die after your **Early Retirement Age**, the survivor annuity your spouse would have received if you had a **Termination of Employment** or Retirement on the day before your death and received distribution of benefits in the form of an immediate **50% Joint and Survivor Annuity**, or
- If you die on or before your **Early Retirement Age**, the survivor annuity your spouse would have received if you had a **Termination of Employment** on the day of your death, survived to your Early Retirement Date, received distribution of benefits in the form of a **50% Joint and Survivor Annuity** on your **Early Retirement Date**, and died on the day after your Early Retirement Date.

Retirement Benefit means the monthly benefit that you accrue under the Plan. The normal form of this benefit is a single life annuity. If you were a participant in the Citizens Pension Plan prior to January 1, 1976, the normal form of benefit is a single life annuity with a 10-year term certain.

Severance from Service Date means the earliest of:

- The day of your Retirement, **Termination of Employment**, or death,
- The second anniversary of your absence for Medical or Family Leave, and
- The first anniversary of the first day of a period in which you remain absent from service for any reason other than quitting, discharge, retirement or death.

If you incur a **Permanent Disability**, your Severance from Service Date will be the earliest of the following:

- The day on which you recover from the disability;

- Your 65th birthday;
- The day you begin to receive distribution of your **Retirement Benefits**; or
- The day this Plan is terminated or the accrual of benefits under this Plan otherwise ceases.

Termination of Employment means the termination of your employment with UES, whether voluntary or involuntary, for any reason, including but not limited to, quit or discharge.

Vesting or **vested** means a right to receive a benefit that cannot be taken away from you. A **Vested benefit** means the nonforfeitable portion of your **Retirement Benefit**. You will become 100% **vested** after five (5) years of **Vesting Service.**

Vesting Service means your aggregate **Periods of Service** and any periods that are required by law to be credited to you for periods of military service. The following periods are not counted as **Vesting Service**:

- Any periods preceding a **Period of Severance** that is 60 consecutive months or more if you had no **Vested Interest**;
- Any periods preceding a **Period of Severance** of at least 12 consecutive months, unless you are credited with a **Period of Service** of one year after that **Period of Severance;**
- Any periods while your **Employer** is not **UES** or an affiliated employer; and
- **Periods of Service** prior to your 18th birthday.

If you became a Participant in this Plan on August 11, 2003, and you were an active participant in the Citizens Pension Plan on August 10, 2003, your Vesting Service includes periods prior to August 11, 2003 credited to you under the terms of the Citizens Pension Plan, including its provisions disregarding service due to a period of severance.

A Final Word

As explained at the outset, this booklet provides a summary description of the Pension Plan for Employees of Unisource Energy Services. It highlights the main provisions of the Plan but is subject to the terms and provisions of the Plan Document. If this booklet and the official plan document vary in the description of the Plan, the plan document is the final authority.

This description of your pension benefits is not an employment contract or any type of employment guarantee.

GENERAL PLAN INFORMATION

Plan Name:	Pension Plan for Employees of Unisource Energy Services
Plan Sponsor and Address:	Tucson Electric Power Company 1 South Church Avenue, Suite 200 Tucson, AZ 85701
Employer Identification Number:	86-0062700
Plan Number:	003
Plan Administrator:	Pension Committee c/o Tucson Electric Power Company 1 South Church Avenue, Suite 200 Tucson, AZ 85701 Telephone (520) 571-4000 The Plan Administrator is designated as an agent for all purposes of legal process. Service of legal process may be made upon the Plan Administrator.
Type of Administration:	Committee appointed by Board of Directors of the Company.
Funding Medium:	Trust Fund
Trustee:	State Street Bank and Trust Company
Trustee's Address:	One Enterprise Drive North Quincy, MA 02171

SUMMARY PLAN DESCRIPTION OF THE PENSION PLAN FOR EMPLOYEES OF UNISOURCE ENERGY SERVICES

Effective August 11, 2003

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SUMMARY PLAN DESCRIPTION OF THE PENSION PLAN FOR EMPLOYEES OF UNISOURCE ENERGY SERVICES

Introduction

This document constitutes the Summary Plan Description ("SPD") for the Pension Plan for Employees of Unisource Energy Services (the "Plan"). The Plan is a defined benefit pension plan that Unisource Energy Services ("UES") has adopted for eligible employees. The Plan became effective as of August 11, 2003.

Few goals are of greater long-range importance than providing for a financially secure retirement. That is why Unisource Energy Services ("UES") sponsors this Plan for you and other eligible employees. The Plan is designed to provide you with retirement income for life based on your salary and the years you work for the UES or any other participating company ("Employer"). When your benefits under this Plan are combined with Social Security and your personal savings, it offers valuable financial security for your retirement years.

On August 11, 2003, Tucson Electric Power Company acquired certain assets and liabilities of Citizens Communications Company ("Citizens"). In connection with that acquisition, certain Citizens employees who were active participants in the Citizens Pension Plan became employees of UES. To the extent that those employees will also be entitled to benefits under this Plan, their benefits from this Plan will be integrated with the benefits provided from the Citizens Pension Plan.

Some terms in the summary are technical. See the Glossary in Appendix A starting at page 24 at the back of the SPD for the definition of any capitalized term you do not understand. If you still have questions, please call the Benefits Office for additional help.

You should read this summary closely so you understand how the Plan works. However, because this is a summary, not every provision is described and the description of certain provisions has been simplified. Full details are contained in the Plan document, which is a legal text governing the operation of the Plan. Copies of the Plan document are available to review in the Benefits Office during regular business hours. If you have any questions, contact the Plan Administrator. This SPD does not interpret, extend or change the Plan in any way. If there are any inconsistencies between this SPD and the Plan document, the provisions of the Plan document will govern your rights and benefits.

Eligibility and Enrollment

When Are You Eligible to Participate in this Plan?

Former Citizens Employees. If you were an active participant in the Citizens Pension Plan on August 10, 2003 -- the day before Citizens was acquired, you automatically became a Participant in this Plan as of August 11, 2003, if on that date or immediately after the end of a Permitted Leave, you (a) were employed by UES in an eligible class of Employees and (b) earned at least one "Hour of Service" (as defined below).

New Employees. You will become a Participant on the first day of the month on or after the day you become an Eligible Employee. You are an "Eligible Employee" if :

- UES has classified you as a common law employee of UES;
- you are at least age 21; and
- you have earned one year of Eligibility Service, which is a twelve-month period, beginning with your date of hire (or an anniversary of your date of hire) in which you are credited with at least 1,000 Hours of Service.

You are **not** in the class of employees eligible to participate in the Plan if:

- you provide services to UES as an independent contractor or consultant, or pursuant to an employee leasing agreement, or UES has classified you as a leased employee or as contract labor; or
- you are a collective bargaining employee, and your agreement does not specifically provide for your participation in the Plan; or
- you are a non-resident alien.

Defining Hours of Service. An Hour of Service is each hour that you actually work for UES or an affiliated employer. You also receive an Hour of Service for each regularly scheduled work hour that you do not work, but are paid or entitled to be paid due to an approved leave of absence, vacation, illness, jury duty, holiday or disability. However, you will not receive more than 501 hours of service for any single continuous period during which you perform no duties, and you cannot receive double credit for the same period of service.

Hours of Service are also credited for each hour for which back pay has either been paid, awarded or agreed to by a participating company (to the extent not already counted above).

If you are a former Citizens employee who was actively participating in the Citizens Pension Plan on August 10, 2003, your Hours of Service will include any hours credited to you under the terms of the Citizens Pension Plan, taking into account for this purpose the provisions relating to disregarding service due to a period of severance.

Rehired Employees. If you previously worked for UES and have been rehired as an Employee, your eligibility to participate in the Plan and the date you will be considered to be a Participant will depend on several factors, including (1) your years of employment with UES when you left; and (2) the length of time you were gone.

If you are not an Eligible Employee when you are rehired, you will become a Participant in accordance with the eligibility rules that apply for new Employees (described in the prior section).

If you are an Eligible Employee when you are rehired, you will become a Participant as follows:

- If you are gone for less than 12 consecutive months, you will become a Participant as of your date of rehire.
- If you are gone for 12 or more consecutive months, you must earn at least one year of Eligibility Service after your rehire before you will become a Participant. Upon completing a year of Eligibility Service, you will become a Participant effective on your date of rehire.
- If you did not have a vested interest when you left employment and you are gone for 60 or more consecutive months, you will be treated as a new Employee for purposes of reentering the Plan.

The rules regarding participation and credited service upon rehire are quite complex. If you think they may apply to you, please contact the Benefits Office for more detail.

Service with an affiliated employer. If you work for Tucson Electric Power Company or another affiliate which is part of the same corporate group as UES, you will continue to be credited with Hours of Service under the Plan. However, you will not be eligible to become a Participant unless you are employed by UES, and your service with the non-participating company will not count toward increasing your benefit.

Once You Are Eligible to Participate, How Do You Enroll?

Enrollment in the Plan is automatic. You do not have to complete an enrollment form in order to participate. UES's Benefit Office will notify you when you become a Participant in the Plan.

Who Pays For the Plan?

You do not have to contribute toward the cost of your pension benefits. UES contributes the funds to provide for the payment of benefits under the Plan, and those funds are held in trust.

Benefits Payable under the Plan

Plan Benefits At a Glance

The Plan Provides ...	When ...
Normal retirement benefit	At age 65.
Early retirement benefit	At age 55 if you have at least five years of Vesting Service.
Postponed retirement benefit	When you actually retire after age 65.
Benefits at termination of employment	After five years of Vesting Service.
Retirement income to your spouse	If you die after vesting but before benefits start.

Normal Retirement Benefit

You are eligible to retire with full benefits upon reaching your Normal Retirement Date. This is the first day of the month coinciding with or next following your 65th birthday. Your retirement benefit is calculated on the basis of the following:

- Your "Average Compensation,"
- Your "Average Covered Compensation," and
- Your years of "Benefit Service" up to 35 years.

Each of these terms is discussed below. In addition, if you were an active participant in the Citizens Pension Plan on August 10, 2003, and began participation in this Plan on August 11, 2003, your retirement benefit is reduced by the benefit payable to you from the Citizens Pension Plan. Here is the basic benefit formula that is used for calculating your normal retirement benefit when you retire on or after age 65:

Basic Benefit Formula at Normal Retirement Date
1.3% of your Average Compensation
PLUS
0.7% of the excess of your Average Compensation over your Average Covered Compensation
MULTIPLIED BY
Your years of Benefit Service at retirement, up to 35 years
MINUS (for certain former Citizens employees)
The amount of benefit payable to you from the Citizens Pension Plan

For former Citizens employees who began participation in this Plan on August 11, 2003, note that your Average Compensation and Benefit Service with Citizens is counted in calculating your benefits. Your compensation and service with Citizens is determined according to the provisions of the Citizens Pension Plan (as in effect on August 10, 2003, or your earlier termination), and is counted even if your benefit was frozen as of February 1, 2003.

Here are the important terms you need to know to calculate your retirement benefit from the Plan:

Average Compensation. Your Average Compensation is your average monthly basic earnings for the 60 consecutive months of highest pay during the last 120 months of your Benefit Service. If you have less than 60 months of Benefit Service, Average Compensation will be based on the entire period of your service. For the purpose of determining whether months are consecutive, any month during which you have no Benefit Service will be ignored.

Here is an example. Assume your salary is set annually, so your monthly basic earnings are consistent throughout the year:

Year	Earnings	Year	Earnings
2001	$3,083.33	2006	$3,416.67*
2002	$3,166.67	2007	$3,750*
2003	$3,250	2008	$3,916.67*
2004	$3,583.33	2009	$4,083.33*
2005	$3,333.33*	2010 (6 months to 7/1)	$4,666.67*

*Your 60 consecutive months of highest pay are from July 1, 2005 through June 30, 2010. Your average monthly earnings are $3,833.

"Monthly basic earnings" means your monthly rate of base salary or wages paid to you, determined as of the first day of the month. If you are not compensated at a monthly rate, your monthly rate will be determined as 1/12th of your annual rate. Items of compensation other than base salary or wages, such as overtime pay, special remuneration and employer contributions to any employee benefit plan, are excluded from monthly basic earnings.

The following rules apply to the compensation used to determine Average Compensation:

- Compensation considered in any year cannot exceed $200,000. This amount changes based on IRS rules in effect from time to time.
- Compensation includes amounts you elect to have UES contribute on a pre-tax basis to a 401(k) plan, health plan or flexible spending account. However, non-qualified deferred compensation is not included.

Average Covered Compensation. This is the average of the annual Social Security wage bases on which you and your employer pay Social Security taxes during a 35-year period; it changes from year to year based on cost-of-living adjustments to the Social Security taxable wage base. This 35-year period ends on the last day of the calendar year in which you reach your Social Security retirement age. Average Covered Compensation is based on the Social Security law in effect on January 1, 1977.

Benefit Service. Your Benefit Service is all time (including any approved leaves of absence) beginning on the date you began working for UES and ending on your "Severance from Service" date. You have a "Severance from Service" when your employment terminates for any reason, including quit, involuntary termination, retirement or death. In addition, you have a Severance from Service on the first anniversary of a leave of absence, other than a leave due to (a) pregnancy, birth of a child, placement of a child with you in connection with adoption of the child or caring for a child immediately following birth or adoption or (b) any other protected leave under the Family and Medical Leave Act of 1993. You will have a Severance from Service no later than the second anniversary of the beginning of such a Medical or Family Leave (unless you earlier terminate due to quit, involuntary termination, etc.).

The following periods of service, however, are <u>not</u> included in your Benefit Service:

- any period before you became a Participant in the Plan;
- any Period of Severance, even if it is less than one year. A Period of Severance means the time beginning on your last day of work and ending on the date you are re-employed; and
- any period in which you are ineligible to participate in the Plan (for example, because you are employed by a non-participating affiliate).

If you are not Vested in your benefits when you leave employment or otherwise have a Severance from Service and are later rehired, you can lose credit for your prior Benefit Service. This will happen if:

- you have a period of severance of at least 60 consecutive months; or
- you have a period of severance of at least 12 consecutive months, and you do not earn at least 12 months of service after your reemployment with UES or an affiliated employer.

If you are a Part-Time Employee, your Benefit Service will be computed on the basis that 200 Hours of Service with UES is one-tenth (1/10) of a year of Benefit Service. However, no more than one year of Benefit Service will be credited in any Plan Year. "Part-Time Employee" means an employee who is employed and compensated for 28 hours per week or less.

If you were an active participant in the Citizens Pension Plan on August 10, 2003 and became a participant in this Plan on August 11, your Benefit Service will include the Benefit Service credited to you under the terms of the Citizens Pension Plan for purposes of calculating your benefit under the Plan , and the amount of offset of your benefit attributable to your Citizens Pension Plan benefit. Your Citizens' Benefit Service is also used in determining whether you have earned 35 years of Benefit Service. Note that Benefit Service that is disregarded under the Citizens Pension Plan because of a break in your service is similarly disregarded under this Plan.

An Example of the Normal Retirement Benefit Calculation – Assume you decide to retire in 2004 at age 65 with 30 years of Benefit Service. Also assume your Average Compensation is $4,200 per month. Based on your retirement date, your Annual Covered Compensation is $43,992, or $3,666 a month. Therefore, your Average Compensation over Average Covered Compensation is $534. Here's how your normal retirement benefit under this Plan is determined:

Normal Retirement Benefit Calculation Under this Plan

1.3% of your Average Compensation = .013 x $4,200 (A)	$54.60
Plus 0.7% of the excess of Average Compensation over Average Covered Compensation = .007 x $534 (B)	+ $3.74
Total of the two calculations above (A + B = C)	$58.34
Multiplied by the aggregate of your Benefit Service under the Citizens Pension Plan and this Plan (up to 35 years) (S)	x 30
Normal Straight Life retirement benefit (C x S) =	$1,750.20

In this example, your normal Retirement Benefit would be $1,750.20. This is the amount payable to you each month for life beginning at age 65. Keep in mind that your monthly payment will be adjusted if you elect to receive it in any other payment form - for example, in monthly payments over your lifetime and the lifetime of your spouse.

If you are a former Citizens employee who was an active participant in the Citizens Pension Plan on August 10, 2003 and began participation in this Plan on August 11, 2003, any amount payable to you under the Citizens Pension Plan will be subtracted from the amount payable under this Plan. For purposes of the prior example, assume that 29 of the 30 years of Benefit Service were with Citizens, and one year of Benefit Service was under this Plan. Also assume that your Average Compensation under the Prior Plan was $4,100, and Annual Covered Compensation was $3,664 in 2003. Therefore, your Average Compensation over Average Covered Compensation is $436.

Based on these assumptions, your normal Retirement Benefit under the Citizens Pension Plan would be:

$1,634.15 per month on a Straight Life basis. As a result, that amount will be deducted from the amount you will receive from this Plan. Accordingly, you will receive $1,634.15 per month from the Citizens Pension Plan and $116.05 per month from this Plan, for a total retirement benefit of $1,750.20 per month on a Straight Life basis.

Early Retirement Benefit

You may retire as early as the first day of the month coinciding with or next following your 55th birthday, as long as you have completed five years of Vesting Service. For the definition of Vesting Service, see the discussion entitled "How your Vesting Service is Determined," later in the SPD.

Your early Retirement Benefit is your Accrued Normal Retirement Benefit as of the date your employment ends, multiplied by the early retirement fraction described below. Your Accrued Normal Retirement Benefit is the benefit you have earned through the date you stop working (under the normal retirement formula above) but using the Benefit Service you would have had if you had continued working until your Normal Retirement Date (up to 35). This "projected" retirement benefit is then multiplied by the ratio of your actual Benefit Service to the Benefit Service you would have if you continued working to your Normal Retirement Date.

Formula for the Early Retirement Fraction
Your actual Benefit Service as of the date your employment terminates (determined without regard to the 35 year limit)
DIVIDED BY
Your projected Benefit Service as if you had continued working until your Normal Retirement Date (determined without regard to the 35 year limit)

As noted above, your benefit will be subject to a second reduction if you begin receiving payments before your Normal Retirement Date. Your benefit will be reduced by five-twelfths (5/12) of one percent (1%) for each full month for which you receive distribution of your benefits before you turn age 65. This reduction is made because you will be receiving payments over a longer period of time. The reduction is calculated monthly; however, the schedule below gives you an idea of the reduction factors that would apply for selected ages:

Early Retirement Benefit Reduction Schedule

Age at Retirement	Reduction Factor (0.417% multiplied by pre-age 65 months)	Benefit as a % of Normal Retirement Benefit
65	0%	100%
64	5%	95%
63	10%	90%
62	15%	85%
61	20%	80%
60	25%	75%
59	30%	70%
58	35%	65%
57	40%	60%
56	45%	55%
55	50%	50%

If you retire in the middle of a year, the reduction is interpolated based on the first of the month in which your benefit begins.

An Example of the Early Retirement Benefit Calculation -- Assume as in the prior example that you decide to retire in 2004, but you are age 60 with 30 years of Benefit Service. Also assume your Average Compensation is the same, $4,200 per month. Based on your 2004 retirement date, your Annual Covered Compensation is $43,992, or $3,666 per month, and your Average Compensation over Average Covered Compensation is $534. Based on these assumptions, the early Retirement Benefit would be calculated as follows:

Early Retirement Benefit Calculation Under this Plan

1.3% of your Average Compensation = .013 x $4,200 (A)	$54.60
Plus 0.7% of the excess of Average Compensation over Average Covered Compensation = .007 x $534 (B)	+ $3.74
Total of the two calculations above (A + B = C)	$58.34
Multiplied by your Benefit Service projected to normal retirement date (up to 35 years) (S)	x 35
Normal straight life retirement benefit** (C x S) =	$2,041.90
Reduced by the Early Retirement Fraction of 30/35	x .857143
Monthly adjusted straight life benefit payable at age 65	$1,750.20

** Note that this amount will be reduced by amounts payable to you under the Citizens Pension Plan.

As you can see from the calculation, if you leave UES before your Normal Retirement Age, your early retirement benefit expressed as a straight life annuity benefit beginning at age 65 is $1,750.20. If you elect to receive payments before your 65th birthday, your benefit will be reduced by five-twelfths (5/12) of one percent (1%) for each month that you receive distribution of your benefits before you turn 65. In the example used above, if you elect to receive payments immediately after your 60th birthday, you will receive your benefits 60 months before your 65th birthday, so the reduction is 25%. Accordingly, you would receive 75% of $1,750.20, or $1,312.65 each month, commencing as of your 60th birthday. Also keep in mind that your monthly payment will be adjusted if you elect to receive it in any other payment form - for example, in monthly payments over your lifetime and the lifetime of your spouse.

Important: If you plan to retire early and you want to receive your benefits beginning with the first day of the month after your Termination of Employment, you should contact the Benefits Office at least 120 days in advance. Your retirement election must be made within the 90-day period ending on the date you want your retirement benefits to begin.

Postponed Retirement Benefit. You will continue to earn retirement benefits if you work beyond your Normal Retirement Date. In that case, you will receive a retirement benefit beginning on the first day of the month after you retire. Your postponed benefit is determined using the Normal Retirement Benefit formula above, based on your Average Compensation and Benefit Service (not in excess of 35 years) as of the date you retire.

Disability Retirement Benefit. If you are a Participant with five or more years of Vesting Service and you become Permanently Disabled while you are employed by UES, you will be entitled to a disability retirement benefit.

Definition of Permanent Disability and Disability Retirement Date

For purposes of this Plan, you will be considered to have a "Permanent Disability" (or be "Permanently Disabled") if you are determined to be disabled under the UES Long-Term Disability Plan ("LTD Plan"), and the disability continues for at least six (6) consecutive months.

Your Disability Retirement Date is the date that the Committee determines your absence due to the Permanent Disability began.

While you are Permanently Disabled, you will continue to be credited with Benefit Service and Vesting Service until the earliest of:

(1) the later of your Normal Retirement Date or the fifth anniversary of your Disability Retirement Date;

(2) the date you refuse to submit to a medical examination as required to determine whether the Permanent Disability still exists;

(3) the date you cease to be Permanently Disabled;

(4) the date of your death;

(5) the date your LTD Plan benefits cease; or

(6) the date your Retirement Benefit begins.

You can elect to begin your Retirement Benefits when you are eligible for a Normal or Early Retirement Benefit. Your disability retirement benefit will be calculated using the applicable benefit formula (based on whether you will be receiving an early or normal Retirement Benefit), based on your Average Compensation as of your Disability Retirement Date and the Benefit Service credited to you above. Remember that continuing service credits end when you elect to retire.

If you are a Part-Time Employee on your Disability Retirement Date, your Benefit Service will be credited at a rate of one-twentieth (1/20) of a year of Benefit Service for each month of Permanent Disability, with a maximum of six months of Benefit Service credited in any Plan Year.

Keep in mind that if you elect to receive a benefit before your Normal Retirement Age, the Plan's early retirement factors will apply.

Vesting and Forfeiture of Benefits at Termination of Employment

Vesting refers to the extent to which you have a nonforfeitable right to your retirement benefit when you leave UES. If you are credited with five or more Years of Vesting Service, your right to your retirement benefits are fully or 100% vested, and you are entitled to all of the benefits you earned under the Plan when you retire or otherwise leave UES. In addition, regardless of your Vesting Service, your benefits are 100% vested at your Normal Retirement Age if you are actively employed by UES.

How is Vesting Service Determined?

Vesting Service is equal to your aggregate Periods of Service and any periods that are required by law to be credited to you for periods of military service. A Period of Service begins on your Employment Commencement Date and ends on your Severance from Service Date, and includes Periods of Severance under 12 months. The following periods are not counted in determining Vesting Service:

- Any Periods of Severance of 12 months or more;
- Any Periods of Service before a Period of Severance that is 60 consecutive months or more, if benefits were not vested;
- Any Periods of Service before a Period of Severance of at least 12 consecutive months unless you are credited with a one year Period of Service after that Period of Severance; and
- Any Periods of Service prior to your 18th birthday.

A Period of Severance commences on the date your employment terminates, and ends on any subsequent reemployment date. A Period of Severance will not include:

- Credited Leave, which is defined as any leave of absence (1) due to illness or injury (not otherwise required to be credited to you under the Family and Medical Leave Act); or (2) for further education; or Government service as determined by UES;
- Any leave of absence to enter the Armed Forces of the United States (1) through the operation of a compulsory military service law; (2) during a period of declared national emergency; or (3) pursuant to a leave of absence granted by UES, as long as you return to the service of UES within 90 days (or such longer period as may be required by law) after your discharge or release from active duty, or within the period for which leave of absence was granted by UES; or
- Any absence from work due to a leave under the Family and Medical Leave Act.

If you began participation in this Plan or with an affiliated employer on August 11, 2003, your Vesting Service includes the Vesting Service credited to you under the terms of the Citizens Pension Plan, including its provisions disregarding service due to a Period of Severance.

Effect of Termination of Employment

If your employment terminates before your Early Retirement Age (age 55 with 5 or more years of Vesting Service), you will be entitled to receive benefits only if you have at least 5 years of Vesting Service when you leave. If you leave employment before you are fully vested in your benefits, you will forfeit your unvested pension benefits.

Your Termination of Employment Benefits are calculated in the same way as Early Retirement Benefits (described above), using your Benefit and Vesting Service as of the date of Termination of Employment. Your benefits can begin as early as the first of the month on or after your 55th birthday. Remember, benefits will be actuarially reduced if you begin payment before your Normal Retirement Date at a rate of $5/12^{\text{ths}}$ of 1% per month.

If the Actuarial Equivalent present value of your benefits when you leave is $5,000 or less, you will automatically receive your benefit in a single lump sum (which you may elect to have rolled over to a new plan). In contrast, if your benefits exceed $5,000, you will have a choice of the form in which you receive those benefits (see the section below entitled "How Benefits are Paid").

Be sure to notify UES if you have a change in address. This way, UES will be able to contact you when you become eligible for a distribution of your vested benefits.

Any benefit that is not vested will be deemed cashed out on the date you incur a Period of Severance of 12 consecutive months. If you are rehired and earn a Year of Service before you have a five (5) year Period of Severance, your benefit will be restored.

Transfers to Another Employer. If you transfer to an affiliated employer that has not adopted this Plan, you will cease to accrue additional benefits under this Plan.

Re-employment After Retirement.

If you are rehired by UES after you have begun receiving retirement benefits from this Plan before Normal Retirement Date (your sixty-fifth (65) birthday), your benefits will be suspended until you subsequently retire. When you subsequently retire, your benefit will be based upon your Average Compensation and Benefit Service at your subsequent retirement date, reduced by the actuarial value of prior payments you received. If you received a lump sum payment of your vested benefit when you previously left employment, your prior Benefit Service will be disregarded for all purposes of the Plan.

If you are rehired (or continue to be employed by UES) after your sixty-fifth (65th) birthday, your benefits will be suspended for each month in which you are credited with forty (40) or more Hours of Service. You must notify UES in order to resume benefits after you stop being so employed. Your benefits will resume no later than the third month after you stop being so employed, assuming you have given the required notice to UES.

The details regarding the impact of rehire upon the payment, the amount and form of benefits under the Plan are extensive. If you are thinking about returning to work with

UES after commencing your benefits under the Plan, please contact the Plan Administrator for the specific rules that will apply to your situation.

How Benefits are Paid

The Plan allows you to receive your retirement benefits in a variety of ways. You choose the method that best fits your personal financial needs.

Forms of Benefits. If the Actuarial Equivalent present value of your vested benefit exceeds $5,000, you may elect to receive your benefits under several different payment options:

- Life Annuity: This option provides monthly benefits to you for life. When you die, payments end. No income will be paid to anyone else.
- Life Annuity with a five or ten-year certain feature: The 5-year or 10-year life annuity pays reduced monthly benefits to you for life, with guaranteed payments for a period of 60 or 120 months, as you elect. If you die within the guaranteed period, your designated Beneficiary will receive your monthly benefit for the remainder of the period. If you receive monthly benefits for the full guaranteed period during your lifetime, no benefits will be paid after you die. The amount by which your benefit is reduced depends on the option you choose and your age. If your Beneficiary dies before you, you may designate a new Beneficiary.
- 33 1/3, 50%, 66 2/3%, 75%, or 100% Joint and Survivor Annuity Options: These options provide a reduced joint and survivor annuity. A joint and survivor annuity provides a monthly benefit to you for your lifetime. After your death, your Beneficiary will receive the percentage elected of your monthly benefit for the remainder of his or her lifetime. The monthly benefit you receive will be less than a single life annuity because it will be paid over two lifetimes - yours and your Beneficiary's. The amount of the reduction depends on your age and the age of your Beneficiary when benefit payments begin. If your Beneficiary dies before you, you cannot name another Beneficiary, and your payment level will not increase. Benefits end upon your death.
- Voluntary lump-sum distribution: If your vested benefit exceeds $5,000, this option provides a lump-sum distribution. The amount of the lump sum is the Actuarial Equivalent present value of your vested benefit payable on your Annuity Starting Date.

If the Actuarial Equivalent present value of your vested benefit is $5,000 or less, you will automatically receive your benefit in a single lump sum. This applies to both single and married employees. Thereafter, you will not be entitled to any monthly benefit.

Special Rules for Married Participants. If you are married on your Annuity Starting Date, you must receive distribution of your vested benefit in the form of a 50% (or greater) Joint and Survivor Annuity with your spouse as your Beneficiary, unless you and your spouse elect to waive this form of distribution. Your spouse's election must be witnessed by a notary public or the Plan Administrator during the 90-day period ending on your Annuity Starting Date. Your election must state the optional form of benefit that you would like distributed and the time of the distribution, and must designate any non-spouse Beneficiary, including contingent Beneficiaries, which cannot be changed without your spouse's consent (if applicable). A spouse's consent to the waiver, once given, may not be revoked. You may revoke the waiver of a Joint and Survivor Annuity without your spouse's consent at any time prior to your Annuity Starting Date (and if so desired, waive it again before that date so long as the requirements for the waiver are satisfied).

Electing a Payment Method. You must elect the form of payment during the 90-day period preceding your Annuity Starting Date. This election may not be changed after your Annuity Starting Date. Remember to contact us 120 days in advance. As you approach retirement age, you will receive more specific information about your benefit options and payment amounts.

If no election of method of distribution is made and you are single, you will be deemed to have elected a straight life annuity with no ancillary benefits. If you are married, you will be deemed to have selected a 50% Joint and Survivor Annuity with your spouse as the Beneficiary.

Keep in mind that you may be asked to provide copies of your birth certificate, applicable spouse birth certificate and marriage license, and may be asked to provide proof of a divorce or spouse death certificate.

Survivor Benefits

If You Die Before Retirement Benefits Begin. If you die before retirement benefits begin, have a vested benefit in the Plan, and are survived by a spouse to whom you have been married for at least one (1) year at the time of your death, your spouse will be eligible to receive a Qualified Preretirement Survivor Annuity. Your spouse is eligible for this benefit even if you are no longer working when you die. This benefit will be paid to your spouse in the form of an annuity for your spouse's life. If the Actuarial Equivalent present value of the Qualified Preretirement Survivor Annuity does not exceed $5,000, the benefit will be paid as a lump sum.

Amount of Benefit. The amount of the annuity your surviving spouse can receive from the plan is the survivor benefit the spouse would have received if you (1) terminated employment on your date of death or earlier termination date, (2) survived to your earliest retirement age under the plan (or, if later, your actual date of death), (3) elected a 50% Qualified Joint and Survivor Annuity at that time, and then (4) died immediately after you began receiving payments. Note that the benefit is actuarially adjusted to the extent that payments begin before you would have attained age of 65.

When Payments Begin. The distribution to your spouse will begin on the earliest of:

a) the first day of the month following your death, if your death occurs after your Normal Retirement Age;

b) the first day of the month following your Normal Retirement Age if your death occurs prior to that time, unless your spouse elects to receive the benefit before your Normal Retirement Age (but not earlier than the date you would have attained your Early Retirement Date had you survived); and

c) if you die before your Normal Retirement Age, and the Actuarial Equivalent present value of the Preretirement Death Benefit does not exceed $5,000, the first day of the month following your death.

If you die before your Normal Retirement Age, and the present value of your Preretirement Death Benefit exceeds $5,000, your spouse may elect to have distribution of the benefit begin on the first day of any month following the election, but not earlier than your Early Retirement Date or after your Normal Retirement Age.

Special Circumstances

- If you are married, and (a) you give the Committee written notice of your election to commence your retirement benefits on a specific date, or your retirement benefit is to commence on or after your Normal Retirement Date or after you reach age 70½ in the absence of such election, and (b) within 90 days prior to the benefit commencement date, you elect a joint and survivor annuity form of payment with your spouse to receive more than 50% of the amount payable, then your surviving spouse's annuity will be based on the larger amount payable under the joint and survivor annuity.

- If you are married, and (a) you die while employed or while on Permanent Disability after having elected to retire within 90 days of such election and to commence your retirement benefit in the form of a lump-sum payment, and (b) your death occurs prior to the benefit commencement date, a lump-sum payment in the same amount will be payable to your spouse on the date the payment would have been made to you had you lived. In order to receive this lump-sum payment, your spouse must, within 60 days after the date of your death, waive the Preretirement Death Benefit that would otherwise be payable.

If You Die After Retirement Benefits Begin. If you die after you have started to receive your retirement benefit, payments will continue only if you elected a payment form that provides for a survivor benefit to be paid to your designated Beneficiary. You need to understand that a single life annuity provides monthly benefits to you for life. If you elect to have your retirement benefit paid to you in that form, payments end when you die. No income will be paid to anyone else.

No benefit is paid under the plan if you die before retirement benefits begin and you are not survived by a legal spouse.

Taxes and Your Benefits

You are responsible for paying applicable taxes on your benefit when you receive it. Under current tax law, your retirement benefit is not taxable while it remains in the Plan. When you (or your Beneficiary) receive a distribution from the Plan, you are responsible for paying applicable income taxes. If a lump sum payment is made, you may also owe a 10% penalty tax if your retirement benefits are paid to you before age 59½ and you terminate employment before the beginning of the year in which you reach age 55.

In general, you can defer paying taxes if you elect to "rollover" your lump sum payout (that is, have it transferred directly) to a plan that will accept rollovers ("Eligible Retirement Plan"), such as a 401(k) plan, a section 457 government plan, or a section 403(b) annuity, or to a traditional or "conduit" individual retirement account ("IRA"). However, certain types of payments generally cannot be rolled over:

- Payments Spread Over Long Periods: Annuity payments cannot be rolled over because they are part of a series of equal (or almost equal) payments that are made at least once a year and will last for your lifetime or for more than ten (10) years.

- Required Minimum Payments: Beginning in the year you reach age 70½ or retire, whichever is later, a certain portion of your payment cannot be rolled over because it is a required minimum payment that must be paid to you.

If you do not elect a direct rollover of the entire lump sum distribution, the Plan is generally required to withhold 20% of the taxable portion of the amount distributed. You will receive additional information on the rollover or direct transfer option when you terminate employment and are ready to receive a distribution.

If you receive payment of your benefit in the form of an annuity (fixed payments for life), you may elect whether or not to have taxes withheld. If you do not make any election, federal income tax will be withheld automatically. Withholding is applied as if the payments were wages. If you elect not to have withholding apply, or even if you do elect withholding, you may still owe taxes on the payments. You are responsible for payment of any taxes associated with the payments.

Tax laws change from time to time, and the tax impact of receiving payments from the Plan will vary with your individual situation. Because UES cannot give tax advice or counsel, you should consult a professional tax advisor or financial expert for specific advice about your circumstances.

Social Security Benefits

Throughout your working career, both you and UES contribute toward your Social Security benefits through payroll taxes. These benefits are in addition to your benefits under the Plan and provide you with an important source of retirement income. ***You will not receive Social Security benefits automatically. You must apply for them.***

If you were born on or before January 1, 1938, your full Social Security benefits can begin at age 65. If you were born later than that date, your full Social Security benefits can begin between the ages of 65 and 67, depending on your birth date. You can consult the chart at the Social Security Administration's website on the Internet at http://www.ssa.gov/retirechartred.htm for the age when you will be entitled to receive your full benefits. You may begin receiving reduced Social Security benefits at age 62.

If you are married, your spouse also is entitled to receive Social Security benefits in an amount based on your pay or his or her pay – whichever produces the greater benefit.

Additional information about your Social Security benefits and how to apply for them is available through SSA's website at http://www.ssa.gov, or you can contact your local Social Security office. The national toll-free number for Social Security currently is 1-800-772-1213.

Plan Administration

The Plan is administered by a Committee appointed by the President of Tucson Electric Power Company. The Committee consists of at least three members, and its functions include resolving claims for benefits and interpreting and construing the terms of the Plan. The Committee has absolute and exclusive authority to interpret the provisions of the Plan in its discretion. The Committee will appoint a Plan Administrator who will maintain Plan records, and make appropriate reports and disclosures required by ERISA. A Trustee will be appointed to manage and control the trust fund and its assets.

How to Apply for Benefits -- Claims Procedure

To receive benefits under the Plan, you must apply to the Benefit Claims Committee. This section describes how to file a claim and an appeal.

Filing a Claim. There are specific procedures for filing claims and settling disputes. The Benefit Claims Committee can explain these to you. To receive benefits from the Plan, you or your Beneficiary must submit a request in writing to the Benefit Claims Committee. You should contact the Committee at least 90 days before you want to begin receiving your benefits.

If Your Claim is Wholly or Partially Denied. If you file a claim for benefits under the Plan and your claim is denied in whole or in part, you will be notified in writing. The notification will include:

- The reason for the denial;
- The specific Plan provisions on which the denial was based;
- A description of any additional information needed to process your claim; and
- An explanation of the claim review procedure.

Ordinarily you will receive this written notice within 30 days after your claim is filed.

If you disagree with the decision, you have a right to request a review of the denial of your claim. To do so, you, your Beneficiary, or your authorized representative must submit a written request to the Benefit Claims Committee within 60 days of receiving the notice of denial. You may review relevant documents or records and submit your comments in writing. You, your Beneficiary, or your authorized representative will have the right to review all pertinent Plan documents.

You will receive a written decision on your request for review within 60 days of the date the Benefit Claims Committee receives your request unless special circumstances, such as the need to hold a hearing, require an extension of time, in which case the 60-day period shall be extended to 120 days and you will be notified of the extension. You will be notified in writing of the final decision, and this decision shall include the specific reasons for the decision, referring to Plan provisions that set forth those reasons.

If you receive a final denial regarding your claim for benefits, you have certain rights under the law. For more information, see the section entitled "ERISA Rights" on page 21.

Additional Information About the Plan

The following is general information about the Plan, certain federal laws, and your rights under the Plan. Please read this section carefully, paying particular attention to how the Plan is governed by federal law.

Internal Revenue Service (IRS) Limits. Government regulations put a cap on the amount of income an employee may receive under a qualified pension plan. For example, Federal law limits the amount that can be considered as compensation for Plan purposes each year. In addition, the IRS sets certain limitations on the amount that employees can receive from plans like the Plan.

The IRS may adjust these limits from time to time to reflect changes in the cost of living. You will be notified if you are affected by these limits.

Non-assignment of Benefits and Qualified Domestic Relations Orders. You cannot assign the benefits payable to you to another person. One exception is that benefits will be paid according to a valid Qualified Domestic Relations Order (QDRO).

A QDRO is an order from a state court that meets certain legal specifications and directs the Plan to pay all or a portion of a Participant's benefits to a spouse, former spouse, or dependent child.

You will be notified immediately if an attempt is made to assign your benefits through a court order. The Committee is responsible for determining whether or not the order is qualified, and has adopted procedures governing QDROs. You can obtain a copy of those procedures, without charge, by contacting the Benefits Office.

Payment to Minors and Incompetents. If anyone entitled to income from the Plan is a minor or is judged to be physically or mentally incompetent, the Committee may pay the income to someone else for the benefit of the recipient (to a legal guardian, for example).

You may execute a form referred to as a "power of attorney" that authorizes another person or entity to act on your behalf if due to illness or incapacity, you are unable to do so yourself. You must specifically mention in the power of attorney that you are authorizing that person or entity to act on your behalf with regard to your benefits under this Plan. Please contact the Benefits Office for additional information regarding this issue.

Top-Heavy Rules. Under current tax law, if a plan provides more than 60% of its benefits to "key" employees, that plan is considered to be "top heavy." Both "top-heavy" and "key" employees are terms defined under the Code.

At present, the Plan is not top-heavy. In the unlikely event that it becomes top-heavy, you will be notified, your benefits may be adjusted, and your vesting may be accelerated to keep the Plan qualified under IRS regulations.

Continuance of the Plan

Amendment or Termination of the Plan. UES reserves the right to amend the Plan at any time and for any reason by action of the President of Tucson Electric Power Company ("TEP"). UES may also terminate the plan at any time and for any reason by action of the Board of Directors of TEP.

If UES terminates the plan for any reason, the assets in the Plan will be used for the exclusive benefit of Plan Participants and their beneficiaries. Any funds that remain after all benefits are paid to Participants will revert to UES. If you are affected by the termination, you will become 100% vested in your retirement benefit under the Plan, to the extent the benefit is funded.

Plan Insurance. The benefits under this Plan are insured by the Pension Benefit Guaranty Corporation ("PBGC"), a federal insurance agency. If the Plan terminates (ends) without enough money to pay all benefits, the PBGC will step in to administer the Plan and pay retirement benefits. Most people will receive all of the retirement benefits they would have received under the Plan, but some people may lose certain benefits.

The PBGC guarantee generally covers:

- Normal and Early retirement benefits;
- Disability benefits if you become disabled before the Plan terminates; and
- Certain benefits for your survivors.

The PBGC guarantee does not cover:

- Benefits greater than the maximum guarantee amount set by law for the year in which the Plan terminates;
- Some or all of benefit increases and new benefits based on Plan provisions that have been in place for fewer than 5 years at the time the Plan terminates;
- Benefits that are not vested because you have not worked long enough for UES;
- Benefits for which you have not met all of the requirements at the time the Plan terminates;
- Certain early retirement payments (such as supplemental benefits that stop when you become eligible for Social Security) that result in an early retirement monthly benefit greater than your monthly benefit at the plan's Normal Retirement Age; and
- Non-retirement benefits, such as health insurance, life insurance, certain death benefits, vacation pay and severance pay.

Even if some of your benefits are not guaranteed, you may still receive some of those benefits from the PBGC depending on how much money the Plan has and on how much the PBGC collects from employers. For more information on the PBGC and the benefits it guarantees, ask your Plan Administrator or contact the PBGC's Technical Assistance Division, 1200 K Street, N.W., Suite 930, Washington, D.C. 20005-4026 or call 202-326-4000 (not a toll-free number). TTY/TDD users may call the federal relay service toll-free at 1-800-877-8339 and ask to be connected to 202-326-4000. Additional information about the PBGC's pension insurance program is available through the PBGC's website on the Internet at http://www.pbgc.gov.

ERISA Rights

If you are a Participant in the Plan, you are entitled to certain rights and protections under the Employee Retirement Income Security Act of 1974 ("ERISA"). The following is a summary of those rights:

- You may examine, without charge, all Plan documents, including insurance contracts and copies of all documents filed by the Plan with the U.S. Department of Labor, such as detailed annual reports and Plan descriptions. These documents are available during regular business hours.

- You may obtain copies of all Plan documents by writing to the Plan Administrator. There will be a reasonable charge for duplicating documents.

- Each year you will receive a summary of the Plan's annual financial reports. The Plan Administrator is required by law to furnish you with a copy of this information.

- Upon your written request, you may obtain a statement telling whether you have a right to receive a benefit under the Plan, and if so, the amount of the benefit. If you are not eligible for a benefit, the statement will tell how many more years you have to work to get a right to a benefit. This statement is not required to be given more than once a year. It is provided free of charge.

- If your claim for a benefit is denied in whole or in part, you must receive a written explanation of the reason for the denial. You have the right to have the Plan review and reconsider the claim.

In addition to creating rights for Plan Participants, ERISA imposes duties on the people who are responsible for the operation of employee benefit plans. The people who operate the plan are called "fiduciaries." Fiduciaries have a duty to operate the plan prudently and in the interest of all Plan Participants and Beneficiaries. No one, including UES or any other person, may fire you or otherwise discriminate against you in any way to prevent you from obtaining a benefit or exercising your rights under ERISA.

Under ERISA, there are steps you can take to enforce these rights. For instance, if you make a written request for materials from the Plan and do not receive them within 30 days, you may file suit in federal court. In such a case, the court may require the Plan Administrator to provide the materials and pay you up to $110 a day until you receive the materials, unless the materials were not sent because of reasons beyond the control of the Plan Administrator. If you have a claim for benefits that is denied or ignored, in whole or in part, you may file suit in a state or federal court. In addition, if you disagree with the Plan's decision or lack thereof concerning the qualified status of a domestic relations order, you may file suit in a state or federal court.

If it should happen that the Plan fiduciaries misuse the Plan's money, or if you are discriminated against for asserting your rights, you may seek assistance from the U.S. Department of Labor, or you may file suit in a federal court. The court will decide who should pay court costs and legal fees. If you are successful, the court may order the person you have sued to pay these costs and legal fees. If you lose, the court may order you to pay these costs and fees; for example, if it finds that your claim is frivolous.

If you have any questions about the Plan, you should contact the Plan Administrator. If you have any questions about this statement or about your rights under ERISA, or if you need assistance in obtaining documents from the Plan Administrator, you should contact the nearest Area Office of the Employee Benefits Security Administration, U.S. Department of Labor, listed in your telephone directory or the Division of Technical Assistance and Inquiries, Employee Benefits Security Administration, U.S. Department of Labor, 200 Constitution Avenue, N.W., Washington, D.C. 20210.

Appendix A

Glossary of Terms

Actuarial Equivalent means a benefit or amount that replaces another and has the same value as the benefit or amount it replaces based on the applicable actuarial assumptions and interest rates.

Affiliated Company means UES or any entity that is in the same controlled group or under common control with UES in accordance with the rules defined in the Internal Revenue Code.

Annuity Starting Date generally means the first date as of which your vested retirement benefits or **Preretirement Death Benefits** are to begin, or the date on which your lump sum is paid to you.

Beneficiary means the person or persons who would become eligible to receive any benefits under the Plan in the event of your death.

Benefit Claims Committee means the committee designated to review your request for benefits.

Board means the Board of Directors of Tucson Electric Power Company or its authorized delegate.

Code means the Internal Revenue Code of 1986, as amended from time to time.

Committee means the committee appointed by the Board to administer the Plan.

Credited Leave means any leave of absence due to illness, injury, further education or Government service as determined by the **Committee**. This term includes any leave of absence to join the Armed Forces of the United States in connection with a compulsory military service law, during a period of declared national emergency, or if UES grants other military-related leaves of absence, provided you return to work within 90 days (or such longer periods as may be provided by law) after your discharge or release from active duty in the Armed Forces, or within the period for which your leave of absence was granted by UES.

Eligible Retirement Plan means an individual retirement account, individual retirement annuity, annuity plan, or qualified trust, as defined in the **Code**, that accepts your eligible rollover distribution. In the case of an eligible rollover distribution to a surviving spouse, an **Eligible Retirement Plan** is an individual retirement account or individual retirement annuity.

Employee means any person classified and treated by UES as a common-law employee.

Employer means **UES** and any participating company.

Employment Commencement Date generally means the day you are first credited with an **Hour of Service**, or if you had a **Period of Severance**, the day you are first credited with an **Hour of Service** after the **Period of Severance**.

ERISA is the Employee Retirement Income Security Act of 1974, as amended from time to time.

50% Joint and Survivor Annuity means an annuity for your lifetime with a survivor annuity for the life of your surviving spouse where the survivor annuity is 50% of the amount of the annuity payable during the joint lives of you and your spouse. The joint and survivor annuity is at least the **Actuarial Equivalent** of the most valuable form of benefit under the Plan payable to you on your **Annuity Starting Date**. Note, however, if you were participating in the Citizens Pension Plan on December 31, 1975, and if you were to die before receiving a total of 120 monthly payments, then your survivor will receive the amount that would have been payable to you (as though you had not died), until a total of 120 monthly payments have been made. After the 120th month, the amount of the survivor pension will be 50% of the reduced pension. In addition, the survivor annuity will be payable until a total of 120 monthly payments have been made without regard to whether or not your spouse is living. Any such survivor annuity payable after the death of your spouse will be payable to a **Beneficiary**.

Medical or Family Leave means an Employee's leave of absence from employment with an Affiliated Company because of: (a) pregnancy, birth of the Employee's child, placement of a child with the Employee in connection with adoption of the child or caring for a child immediately following birth or adoption or (b) any other reason that would entitle the Employee to take a leave under the Family and Medical Leave Act of 1993. The Employer shall determine the first and last day of any Medical or Family Leave.

Participant means an **Eligible Employee** who is participating in this Plan.

Period of Service means a period (including any periods of **Credited Leave**) beginning when a **Participant** is credited with an **Hour of Service (Employment Commencement Date**) and ending on the **Participant's Severance from Service Date**. For vesting purposes, **Period of Service** includes any **Period of Severance** under 12 months.

If you became a **Participant** in this **Plan** because you were an active participant in the Citizens Pension Plan on August 10, 2003, a **Period of Service** for any period prior to August 11, 2003, will be determined according to the terms of the **Citizens Pension Plan**, including provisions relating to disregarding service due to a **Period of Severance**.

Period of Severance means the time beginning on your last day of work and ending on the date you are re-employed.

Permanent Disability means total disability by bodily or mental injury or disease as determined by the Committee based on a determination made by the insurer under the Company's long-term disability plan or the Social Security Administration provided:

(a) the Employee has five years of Vesting Service;

(b) the Employee becomes entitled to benefits under the Company's long-term disability plan;

(c) the Employee earns at least one Hour of Service as an active Employee of an Employer after the Effective Date; and

(d) such disability shall have existed for a period of six consecutive calendar months.

Permitted Leave means an approved leave of absence from **UES,** including but not limited to military service, illness, disability, **Medical** or **Family Leave**, educational pursuits, service as a juror, temporary employment with a government agency, or any other leave of absence approved by the participating company.

Plan means the Pension Plan for Employees of Unisource Energy Services.

Plan Year means the calendar year.

Preretirement Death Benefit means the death benefit payable under the Plan to your surviving spouse if you die before your **Annuity Starting Date** and the following additional criteria are met:

- you have a vested benefit in the Plan, and
- you have been married to your spouse for at least one (1) year at the time of your death.

Qualified Preretirement Survivor Annuity means an immediate survivor annuity for the life of your spouse, equal to:

- If you die after your **Early Retirement Age**, the survivor annuity your spouse would have received if you had a **Termination of Employment** or Retirement on the day before your death and received distribution of benefits in the form of an immediate **50% Joint and Survivor Annuity**, or
- If you die on or before your **Early Retirement Age**, the survivor annuity your spouse would have received if you had a **Termination of Employment** on the day of your death, survived to your Early Retirement Date, received distribution of benefits in the form of a **50% Joint and Survivor Annuity** on your **Early Retirement Date,** and died on the day after your Early Retirement Date.

Retirement Benefit means the monthly benefit that you accrue under the Plan. The normal form of this benefit is a single life annuity. If you were a participant in the Citizens Pension Plan prior to January 1, 1976, the normal form of benefit is a single life annuity with a 10-year term certain.

Severance from Service Date means the earliest of:

- The day of your Retirement, **Termination of Employment**, or death,
- The second anniversary of your absence for Medical or Family Leave, and
- The first anniversary of the first day of a period in which you remain absent from service for any reason other than quitting, discharge, retirement or death.

If you incur a **Permanent Disability**, your Severance from Service Date will be the earliest of the following:

- The day on which you recover from the disability;

- Your 65th birthday;
- The day you begin to receive distribution of your **Retirement Benefits**; or
- The day this Plan is terminated or the accrual of benefits under this Plan otherwise ceases.

Termination of Employment means the termination of your employment with UES, whether voluntary or involuntary, for any reason, including but not limited to, quit or discharge.

Vesting or **vested** means a right to receive a benefit that cannot be taken away from you. A **Vested benefit** means the nonforfeitable portion of your **Retirement Benefit**. You will become 100% **vested** after five (5) years of **Vesting Service.**

Vesting Service means your aggregate **Periods of Service** and any periods that are required by law to be credited to you for periods of military service. The following periods are not counted as **Vesting Service**:

- Any periods preceding a **Period of Severance** that is 60 consecutive months or more if you had no **Vested Interest**;
- Any periods preceding a **Period of Severance** of at least 12 consecutive months, unless you are credited with a **Period of Service** of one year after that **Period of Severance**;
- Any periods while your **Employer** is not **UES** or an affiliated employer; and
- **Periods of Service** prior to your 18th birthday.

If you became a Participant in this Plan on August 11, 2003, and you were an active participant in the Citizens Pension Plan on August 10, 2003, your Vesting Service includes periods prior to August 11, 2003 credited to you under the terms of the Citizens Pension Plan, including its provisions disregarding service due to a period of severance.

A Final Word

As explained at the outset, this booklet provides a summary description of the Pension Plan for Employees of Unisource Energy Services. It highlights the main provisions of the Plan but is subject to the terms and provisions of the Plan Document. If this booklet and the official plan document vary in the description of the Plan, the plan document is the final authority.

This description of your pension benefits is not an employment contract or any type of employment guarantee.

GENERAL PLAN INFORMATION

Plan Name:	Pension Plan for Employees of Unisource Energy Services
Plan Sponsor and Address:	Tucson Electric Power Company 1 South Church Avenue, Suite 200 Tucson, AZ 85701
Employer Identification Number:	86-0062700
Plan Number:	003
Plan Administrator:	Pension Committee c/o Tucson Electric Power Company 1 South Church Avenue, Suite 200 Tucson, AZ 85701 Telephone (520) 571-4000 The Plan Administrator is designated as an agent for all purposes of legal process. Service of legal process may be made upon the Plan Administrator.
Type of Administration:	Committee appointed by Board of Directors of the Company.
Funding Medium:	Trust Fund
Trustee:	State Street Bank and Trust Company
Trustee's Address:	One Enterprise Drive North Quincy, MA 02171

**UNS GAS, INC.'S RESPONSE TO
STAFF'S SIXTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
April 16, 2009**

TF 6.103 Are there any aspects of the Company's accounting adjustments and revenue requirement claim which represents a conscious deviation from the principles and policies established in prior Commission Orders? If so, identify each area of deviation, and for each deviation explain the Company's perception of the principle established in the prior Commission orders, how the Company's proposed treatment in this rate case deviates from the principles established in the prior Commission orders, and the dollar impact resulting from such deviation. Show which accounts are affected and the dollar impact on each account for each such deviation.

RESPONSE: The only accounting adjustments that knowingly deviate from the Commission's prior decision for UNS Gas are: the "Customer Advances Adjustment" and the "Incentive Compensation Adjustment". The only known deviation within revenue requirements is the expense associated with "Supplemental Executive Retirement Plan."

In the prior Commission decision, 100% of the customer advances balance was deducted from rate base. The Company is requesting that the portion of the advances already expended by the end of the test year, but not included in rate base, be excluded from the advances credit to rate base. This is fully explained in the Direct Testimony of UNS Gas witness Mr. Dallas Dukes. The dollar and accounts impact can be found in the pro forma work papers provided in response to Commission Staff's data request JMK 1.1 workpapers supporting the adjustment.

In the prior Commission decision, 50% of the incentive compensation expense was excluded from revenue requirements. UNS Gas is requesting full recovery of the normal and recurring level of incentive compensations expense. This is fully explained in the Direct Testimony of UNS Gas witness Mr. Dallas Dukes. The dollar and accounts impact can be found in the pro forma work papers provided in response to Commission Staff's data request JMK 1.1 workpapers supporting the adjustment.

In the prior Commission decision 100% of the supplemental executive retirement plan expense was excluded from revenue requirements. UNS Gas is requesting full recovery of the normal and recurring level of the expense contained within the test year. The dollar and accounts impact are being provided in response to TF 6.64.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

UNS GAS, INC.'S SUPPLEMENTA RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS DOCKET NO. G-04204A-08-0571 May 14, 2009

TF 6.92 Please provide complete copies of any bonus programs or incentive award programs in effect at the Company for the most recent three years. Identify all incentive and bonus program expense incurred in 2008 and 2009. Identify the accounts charged. Identify all incentive and bonus program expense charged or allocated to the Company from affiliates in 2008 and 2009.

RESPONSE: See response to TF 6.64 for description of bonus program available to UNS Gas Non-Union Employees. Union employees are not eligible for a bonus program.

Long-term Incentive Program: UNS Gas Officers are eligible to participate in a Long-term Incentive Program. Please see the PDF File TF 6.92 Officer LTI (Confidential), Bates Nos. UNSG(0571)07992 to UNSG(0571)07993 on the enclosed CD for descriptions of the terms of the 2008 long-term incentive program.

Bates Nos. UNSG(0571)07992 to UNSG(0571)07993 contain confidential information and are being provided pursuant to the terms of the Protective Agreement.

SUPPLEMENTAL RESPONSE: See response to TF 6.64 for description of bonus program available to UNS Gas Non-Union Employees. Union employees are not eligible for a bonus program.

Long-term Incentive Program: UNS Gas Officers are eligible to participate in a Long-term Incentive Program. Please see the PDF File provided in response to TF 6.92 on April 17, 2009, TF 6.92 Officer LTI (Confidential), Bates Nos. UNSG(0571)07992 to UNSG(0571)07993, for descriptions of the terms of the 2008 long-term incentive program.

Bates Nos. UNSG(0571)07992 to UNSG(0571)07993 contain confidential information and are being provided pursuant to the terms of the Protective Agreement.

Expense:

- UNS Gas Incentive Compensation ("PEP:) Program (excluding officers):

  2008 = $268,127.72

  Charged to Account 50100, Sub 0000, Expenditure Type 050, FERC 0870, 0874, 0880, 0887, 0920

UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS DOCKET NO. G-04204A-08-0571 May 14, 2009

- UNS Gas Incentive Compensation (PEP) Program Officer portion of Incentive: Allocated by Massachusetts Formula

  2008 = $129,761.00

  Charged to Account 52100, Sub 0000, Expenditure Type 052, FERC 0920
- Stock Option Expense: Allocated by Massachusetts Formula

  2008 = $129,850.02

  Charged to Account 50100, Sub 4014, Expenditure Type 085, FERC 0920
- Dividend Equivalents on Stock Units: Allocated by Massachusetts Formula

  2008 = $18,780.67

  Charged to Account 50100, 79040, Sub 3604, Expenditure Type 085, FERC 0920
- Performance Share Award: Allocated by Massachusetts Formula

  2008 = $34,689.17

  Charged to Account 50100, Sub 4013, Expenditure Type 085, FERC 0920
- Dividend Equivalent on Stock Options: Allocated by Massachusetts Formula

  2008 = $23,806.64

  Charged to Account 50100, 79040, Sub 4019, Expenditure Type 085, FERC 0920
- Spot Awards

  2008 = $12,535.05

  Charged to Account 50100, Sub 0000, Expenditure Type 055, FERC 0920
- Directors Stock Awards: Allocated by Massachusetts Formula

  2008 = $72,263.73

  Charged to Account 79040, Sub 4020, Expenditure Type 230, FERC 0930

UNS Gas is unable to provide 2009 results until the quarterly reports have been filed with the SEC .

RESPONDENT: Maya Liddell

WITNESS: Dallas Dukes

**UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO
STAFF'S SIXTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
May 14, 2009**

SUPPLEMENTAL RESPONSE: The following items have been updated to reflect January 2009 through March 2009 data.

Expense (charged or allocated):

- UNS Gas Incentive Compensation ("PEP") Program (excluding officers):

  2009 = $63,000.00

  Charged to Account 50100, Sub 0000, Expenditure Type 050, FERC 0870, 0874, 0880, 0887, 0920

- UNS Gas Incentive Compensation ("PEP") Program Officer portion of Incentive: Allocated by Massachusetts Formula

  2009 = $28,749.00

  Charged to Account 52100, Sub 0000, Expenditure Type 052, FERC 0920

- Stock Option Expense: Allocated by Massachusetts Formula

  2009 = $35,936.79

  Charged to Account 50100, Sub 4014, Expenditure Type 085, FERC 0920

- Dividend Equivalents on Stock Units: Allocated by Massachusetts Formula

  2009 = $2,231.72

  Charged to Account 50100, 79040, Sub 3604, Expenditure Type 085, 230, FERC 0920

- Performance Share Award: Allocated by Massachusetts Formula

  2009 = $21,637.38

  Charged to Account 50100, Sub 4013, Expenditure Type 085, FERC 0920

- Dividend Equivalent on Stock Options: Allocated by Massachusetts Formula

  2009 = $2,811.89

  Charged to Account 50100, 79040, Sub 4019, Expenditure Type 085, 230, FERC 0920

UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS DOCKET NO. G-04204A-08-0571 May 14, 2009

- Spot Awards

  2009 = N/A

  Charged to Account 50100, Sub 0000, Expenditure Type 055, FERC 0920

- Directors Stock Awards: Allocated by Massachusetts Formula

  2009 = $16,334.99

  Charged to Account 79040, Sub 4020, Expenditure Type 230, FERC 0930

RESPONDENT: Gabrielle Camacho/Warner Jones

WITNESS: Dallas Dukes

UniSource Energy

One South Church Avenue
Tucson, Arizona 85701

March 23, 2009

Paul J. Bonavia
Chairman of the Board

(520) 571-4000

Dear Shareholders:

You are cordially invited to attend the UniSource Energy Corporation 2009 Annual Shareholders' Meeting (the "Meeting") to be held on Friday, May 8, 2009, at the FOX Theatre, 17 West Congress, Tucson, Arizona. The Meeting will begin promptly at 10:00 a.m., Mountain Standard Time, so please plan to arrive earlier. No admission tickets will be required for attendance at the Meeting.

Directors and officers will be available before and after the Meeting to speak with you. During the Meeting, we will answer your questions regarding our business affairs and we will consider the matters explained in the enclosed Proxy Statement.

We have enclosed a proxy card that lists all matters that require your vote. Please complete, sign, date and mail the proxy card as soon as possible, whether or not you plan to attend the Meeting. You may also vote by telephone or the Internet, as explained on the enclosed proxy card. If you attend the Meeting and wish to vote your shares personally, you may revoke your proxy at that time.

Your interest in and continued support of UniSource Energy Corporation are much appreciated.

Sincerely,

UNISOURCE ENERGY CORPORATION

Paul J. Bonavia
Chairman of the Board, President and
Chief Executive Officer

NOTICE OF ANNUAL SHAREHOLDERS' MEETING

To the Holders of Common Stock of
UniSource Energy Corporation

We will hold the 2009 Annual Shareholders' Meeting of UniSource Energy Corporation at the FOX Theatre, 17 West Congress, Tucson, Arizona, on Friday, May 8, 2009, at 10:00 a.m., Mountain Standard Time ("MST"). The purpose of the Meeting is to:

1. elect 14 directors to our Board of Directors for the ensuing year;
2. ratify the selection of the Independent Registered Public Accounting Firm for 2009; and
3. consider any other matters which properly come before the Meeting.

Only shareholders of record at the close of business on March 16, 2009, are entitled to vote at the Meeting.

We have enclosed with this notice: (i) our 2008 annual report on Form 10-K; (ii) the Proxy Statement; (iii) the Chairman's letter to shareholders; and (iv) a stock performance chart. Proxy soliciting material is first being made available in electronic form, on or about March 27, 2009. Your proxy is being solicited by our Board of Directors.

Please complete, sign, date and mail the enclosed proxy card as soon as possible, or vote by telephone or the Internet, as explained on the enclosed proxy card.

Linda Kennedy

Linda H. Kennedy
Corporate Secretary

Dated: March 23, 2009

YOUR VOTE IS IMPORTANT

EACH SHAREHOLDER IS URGED TO COMPLETE, SIGN, DATE AND RETURN PROMPTLY THE ENCLOSED PROXY CARD BY MAIL, OR TO VOTE BY TELEPHONE OR THE INTERNET, AS EXPLAINED ON THE ENCLOSED PROXY CARD. IF THE MAIL OPTION IS SELECTED, USE THE ENCLOSED ENVELOPE, WHICH DOES NOT REQUIRE POSTAGE IF MAILED IN THE UNITED STATES. RETURNING A SIGNED PROXY WILL NOT PROHIBIT YOU FROM ATTENDING THE MEETING AND VOTING IN PERSON IF YOU SO DESIRE.

UNISOURCE ENERGY CORPORATION
One South Church Avenue
Tucson, Arizona 85701

ANNUAL SHAREHOLDERS' MEETING
PROXY STATEMENT

ANNUAL MEETING:

May 8, 2009	FOX Theatre
10:00 a.m., MST	17 West Congress
	Tucson, AZ 85701

RECORD DATE:

The record date is March 16, 2009 ("Record Date"). If you were a shareholder of record at the close of business on the Record Date, you may vote at the 2009 Annual Shareholders' Meeting ("Meeting") of UniSource Energy Corporation ("UniSource Energy" as well as references to the "Company," "we," "our" and "us"). At the close of business on the Record Date, we had 35,610,300 shares of common stock outstanding.

AGENDA:

1. Proposal One: Elect 14 directors to our Board of Directors ("Board") for the ensuing year.
2. Proposal Two: Ratify the selection of the Independent Registered Public Accounting Firm for 2009.
3. Proposal Three: Consider any other matters which properly come before the Meeting and any adjournments.

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM:

Representatives of PricewaterhouseCoopers, LLP are expected to be present at the Meeting with the opportunity to make a statement and respond to appropriate questions from our shareholders.

PROXIES:

In accordance with rules and regulations recently adopted by the Securities and Exchange Commission (the "SEC"), instead of mailing a printed copy of our proxy materials to each shareholder of record, we are now furnishing proxy materials to our shareholders on the Internet. If you received a Notice of Internet Availability of Proxy Materials by mail, you will not receive a printed copy of the proxy materials other than as described therein. Instead, the Notice of Internet Availability of Proxy Materials will instruct you as to how you may access and review all of the important information contained in the proxy materials. If you received a Notice of Internet Availability of Proxy Materials by mail and would like to receive a printed copy of our proxy materials, you should follow the instructions included in the Notice of Internet Availability of Proxy Materials.

It is anticipated that the Notice of Internet Availability of Proxy Materials is first being sent to shareholders on or about March 27, 2009. The proxy statement and the form of proxy relating to the 2009 Annual Meeting are first being made available to shareholders on or about March 27, 2009.

PROXIES SOLICITED BY:

The Board.

REVOKING YOUR PROXY:

You may revoke your proxy before it is voted at the Meeting. To revoke, follow the procedures listed on page 4 under "Voting Procedures/Revoking Your Proxy."

COMMENTS:

Your comments about any aspects of our business are welcome. You may use the space provided on the proxy card for this purpose, if desired. Although we may not respond on an individual basis, your comments help us to measure your satisfaction, and we may benefit from your suggestions.

PLEASE VOTE – YOUR VOTE IS IMPORTANT

Prompt return of your proxy will help reduce the costs of re-solicitation.

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* We expect to vote on this item at the Meeting.

VOTING PROCEDURES/REVOKING YOUR PROXY

You can vote by telephone, the Internet, mail or in person.

You may vote in person or by a validly designated proxy, or, if you or your proxy will not be attending the meeting, you may vote in one of three ways:

1. Vote by Internet. The website address for Internet voting is on your Notice of Internet Availability of Proxy Materials. Internet voting is available 24 hours a day;

2. Vote by telephone. The toll-free number for telephone voting is on your proxy card. Telephone voting is available 24 hours a day; or

3. Vote by mail. If you have requested and received a copy of our proxy materials, mark, date, sign and mail promptly a proxy card (a postage-paid envelope will be provided for mailing in the United States).

If you vote by telephone or Internet, DO NOT mail a proxy card.

Under Arizona law, a majority of the shares entitled to vote on any single matter which may be brought before the Meeting will constitute a quorum. Business may be conducted once a quorum is represented at the Meeting. If a quorum exists, action on a matter other than the election of directors will be deemed approved if a majority of votes is cast in favor of the matter.

Directors are elected by a plurality of votes.

Directors are elected by a plurality of the votes cast by the shares entitled to vote if a quorum is present. A plurality means receiving the largest number of votes, regardless of whether that is a majority. Withheld votes will be counted as being represented at the Meeting for quorum purposes but will not have an effect on the vote.

You may cumulate your votes for directors.

In the election of directors, each shareholder has the right to cumulate his votes by casting a total number of votes equal to the number of his shares of common stock multiplied by the number of directors to be elected. He may cast all of such votes for one nominee or distribute such votes among two or more nominees. For any other matter that may properly come before the Meeting, each share of common stock will be entitled to one vote.

You can revoke your proxy after sending it in by following these procedures.

Any shareholder giving a proxy has a right to revoke that proxy by giving notice to UniSource Energy in writing directed to the Corporate Secretary, UniSource Energy Corporation, One South Church Avenue, Suite 1820, Tucson, Arizona 85701, or in person at the Meeting at any time before the proxy is exercised. Those who fail to return a proxy or fail to attend the Meeting will not count towards determining any required plurality, majority or quorum.

The shares represented by an executed proxy will be voted for the election of directors or withheld in accordance with the specifications in the proxy. If no specification is made in an executed proxy, the proxy will be voted in favor of the nominees as set forth herein.

Proxy Solicitation

We will bear the entire cost of the solicitation of proxies. Solicitations will be made primarily by mail. In addition, we may make additional solicitation of brokers, banks, nominees and institutional investors pursuant to a special engagement of BNY Mellon Shareholder Services. Solicitations may also be made by telephone, facsimile or personal interview, if necessary, to obtain reasonable representation of shareholders at the Meeting. Our employees may solicit proxies but they will not receive additional compensation for such services. We will request brokers or other persons holding shares in their names, or in the names of their nominees, to forward proxy materials to the beneficial owners of such shares or request authority for the execution of the proxies. We will reimburse brokers and other persons for reasonable expenses they incur in sending these proxy materials to you if you are a beneficial holder of our shares.

UNISOURCE ENERGY SHARE OWNERSHIP

Security Ownership of Management

The following table sets forth the number and percentage of shares of UniSource Energy common stock beneficially owned as of March 1, 2009 and the nature of such ownership by each of our directors (all of whom are nominees), our Chief Executive Officer for 2008 ("CEO" or "Mr. Pignatelli") and our four other most highly compensated executive officers (together with our CEO, the "Named Executives") as of March 1, 2009 and all directors and officers as a group. Ownership includes direct and indirect (beneficial) ownership, as defined by the SEC rules.

Name and Title of Beneficial Owner	Amount and Nature of Beneficial Ownership(1)					Other(2)		
	Directly Owned Shares	Shares Purchased Under the 401(k) Plan	Shares Subject to Options Exercisable Within 60 Days	Total Beneficial Ownership	Percent of Class	Restricted Stock Units	Deferred Shares Under Deferred Compensation Plan	Total
James S. Pignatelli Chairman, President and Chief Executive Officer(3)	114,324	21,030	695,089	830,443	2.3%	0	30,971	**861,414**
Lawrence J. Aldrich Director	3,912	0	0	3,912	*	5,420	0	**9,332**
Barbara M. Baumann Director	0	0	0	0	*	3,869	8,965	**12,834**
Larry W. Bickle Director	9,852	0	8,358	18,210	*	4,492	0	**22,702**
Elizabeth T. Bilby Director	705	0	8,358	9,063	*	5,876	4,194	**19,133**
Harold W. Burlingame Director	4,625	0	8,358	12,983	*	6,636	0	**19,619**
John L. Carter Director	23,817	0	0	23,817	*	5,171	11,315	**40,303**
Robert A. Elliott Director	1,813	0	1,196	3,009	*	4,324	0	**7,333**
Daniel W. L. Fessler Director	2,511	0	2,358	4,869	*	8,942	0	**13,811**
Louise L. Francesconi Director(4)	0	0	0	0	*	0	0	**0**
Kenneth Handy(5) Director	25,662	0	0	25,662	*	0	0	**25,662**
Warren Y. Jobe Director	1,313	0	6,358	7,671	*	6,266	0	**13,937**
Ramiro G. Peru Director	1,000	0	0	1,000	*	1,565	0	**2,565**
Gregory A. Pivirotto Director	400	0	0	400	*	1,565	0	**1,965**
Joaquin Ruiz Director	300	0	0	300	*	3,869	0	**4,169**
Kevin P. Larson Senior Vice President Chief Financial Officer and Treasurer	43,199	2,605	96,235	142,039	*	0	1,323	**143,362**

Name and Title of Beneficial Owner	Amount and Nature of Beneficial Ownership(1)					Other(2)		
	Directly Owned Shares	Shares Purchased Under the 401(k) Plan	Shares Subject to Options Exercisable Within 60 Days	Total Beneficial Ownership	Percent of Class	Restricted Stock Units	Deferred Shares Under Deferred Compensation Plan	Total
Raymond S. Heyman Senior Vice President and General Counsel	6,296	3,455	86,542	96,293	*	0	87	**96,380**
Michael J. DeConcini Senior Vice President and Chief Operating Officer, Transmission and Distribution	13,932	5,480	163,769	183,181	*	27,214	971	**211,366**
Karen G. Kissinger Vice President, Controller and Chief Compliance Officer	42,789	0	37,037	79,826	*	0	1,985	**81,811**
All directors and executive officers as a group	358,339	58,635	1,290,400	1,707,374	4.8%	85,209	62,655	**1,855,238**

*Represents less than 1% of the outstanding common stock of UniSource Energy.

(1) Amounts include the following:
- Any shares held in the name of the spouse, minor children or other relatives sharing the home of the director or officer. Except as otherwise indicated below, the directors and officers have sole voting and investment power over the shares shown. Voting power includes the power to direct the voting of the shares held, and investment power includes the power to direct the disposition of the shares held.
- Shares subject to options exercisable within 60 days, based on information from E*Trade, UniSource Energy's stock option plan administrator.
- Equivalent share amounts allocated to the individuals' 401(k) Plan which, since June 1, 1998, has included a UniSource Energy Stock Fund investment option.

(2) While amounts in the "Other" column do not represent a right of the holder to receive stock within 60 days, these amounts are being disclosed because management believes they reflect similar objectives of 1) encouraging directors and officers to have a stake in the Company, and 2) aligning interests of directors and officers with those of shareholders. Under our non-employee director compensation program, non-employee directors receive an annual grant of restricted stock units that have an underlying value equal to one share of UniSource Energy common stock. The value of the restricted stock units fluctuates based on changes in the Company's stock price. All restricted stock unit grants to directors vest at the earlier of the next annual meeting following the grant date or the first anniversary of grant and are distributed in actual shares of Company stock in January following termination of Board service. Similarly, the value of deferred stock units fluctuates based on changes in the Company's stock price. Under the terms of the plan, distributions of deferred shares will be made in cash, unless the participant elects to receive the deferred shares in Company stock on dates selected by the director or the officer following termination of service. In our view, restricted stock units and deferred stock units are tantamount to actual stock ownership as the non-employee director and officer (in the case of deferred stock units) bear the risk of ownership during the restricted and deferral periods.

(3) Mr. Pignatelli retired effective as of January 1, 2009. His successor, Paul Bonavia, became Chairman of the Board, President and Chief Executive Officer, effective January 1, 2009. Since Mr. Bonavia does not beneficially own any UniSource Energy common stock which has vested, Mr. Bonavia was not included in this table.

(4) Ms. Francesconi was appointed to the Board, effective August 14, 2008.

(5) Mr. Handy retired from his position as a director effective as of January 1, 2009 and, therefore, is not being nominated as a director.

Security Ownership of Certain Beneficial Owners

As of March 1, 2009, based on information reported in filings made by the following persons with the SEC or information otherwise known to us, the following persons were known or reasonably believed to be, as more fully described below, the beneficial owners of more than 5% of our common stock:

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common	Barclays Global Investors, NA 45 Fremont Street San Francisco, CA 94105	3,321,505[(1)]	9.4%
Common	Luminus Management, LLC 1700 Broadway, 38th Floor New York, NY 10019	3,296,379[(2)]	9.3%
Common	Prospector Partners, L.L.C. 370 Church Street Guilford, CT 06437	2,670,686[(3)]	7.3%
Common	T. Rowe Price Associates, Inc. 100 E. Pratt Street Baltimore, MD 21202	2,506,350[(4)]	7.0%
Common	Wellington Management Co., LLP 75 State Street Boston, MA 02109	2,353,955[(5)]	6.8%
Common	Duquesne Capital Management, LLC 40 W. 57th Street, 25th Floor New York, NY 10019	1,781,000[(6)]	5.0%

(1) In a statement (Schedule 13G) filed with the SEC on February 6, 2009, Barclays Global Investors, NA, indicated that it has sole voting power over 2,801,812 shares of our common stock and sole dispositive power over 3,321,505 shares of our common stock. The filing indicated that the 3,321,505 shares are owned by Barclays Global Investors, NA (744,963 shares), Barclays Global Fund Advisors (2,539,447 shares), Barclays Global Investors, LTD (23,507 shares), Barclays Global Investors Australia Limited (13,588).

(2) In a statement (Schedule 13G) filed with the SEC on February 17, 2009, Luminus Management LLC, indicated it has sole voting and sole dispositive power over 3,296,379 shares of our common stock.

(3) In a statement (Schedule 13G) filed with the SEC on February 17, 2009, Prospector Partners, L.L.C. ("Prospector Partners"), indicated it has sole voting and sole dispositive power over 1,875,672 shares, and shared voting and shared dispositive power over 795,014 shares of our common stock. Prospector Partners shares investment discretion over 795,014 shares with White Mountains Advisors LLC ("White Mountains"), pursuant to a sub-advisory agreement between Prospector Partners and White Mountains.

(4) In a statement (Schedule 13G) filed with the SEC on February 13, 2009, T. Rowe Price Associates, Inc. ("Price Associates"), indicated it has sole voting power over 288,933 shares and sole dispositive power over 2,506,350 shares of our common stock. These securities are owned by various individual and institutional investors which Price Associates serves as investment adviser with power to direct investments and/or sole power to vote the securities. For purposes of the reporting requirements of the Securities Exchange Act of 1934, as amended, Price

Associates is deemed to be a beneficial owner of such securities; however, Price Associates expressly disclaims that it is, in fact, the beneficial owner of such securities.

(5) In a statement (Schedule 13G) filed with the SEC on February 17, 2009, Wellington Management Co. LLP, indicated it has shared voting power over 1,826,595 shares and shared dispositive power over 2,353,955 shares of our common stock.

(6) In a statement (Schedule 13G) filed with the SEC on February 12, 2009, Duquesne Capital Management, LLC, indicated it has shared voting power over 1,781,000 shares of our common stock and shared dispositive power over 1,781,000 shares of our common stock.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended, and regulations of the SEC require our executive officers, directors and persons who beneficially own more than 10% of our common stock, as well as certain affiliates of those persons, to file initial reports of ownership and transaction reports covering any changes in ownership with the SEC and the New York Stock Exchange ("NYSE"). SEC regulations require these persons to furnish us with copies of all reports they file pursuant to Section 16(a).

Based solely upon a review of the copies of the reports received by us and on written representations of our directors and officers, we believe that during fiscal year 2008, all filing requirements applicable to executive officers and directors were complied with in a timely manner.

PROPOSAL ONE: ELECTION OF DIRECTORS

General Information

At the Meeting, our shareholders of record will elect 14 directors to serve on our Board for the ensuing year and until their successors are elected and qualified, which include our new Chief Executive Officer, Paul J. Bonavia, who joined UniSource Energy on January 1, 2009. The shares represented by executed proxies in the form provided, unless withheld, will be voted for the 14 nominees listed below, or, in the discretion of the persons acting as proxies, will be voted cumulatively for one or more of such nominees. All of the current nominees are present members of the Board. All of the nominees have consented to serve if elected. If any nominee becomes unavailable to serve for any reason, or a vacancy should occur before the election, it is the intention of the persons designated as proxies to vote, in their discretion, for other nominees.

BOARD NOMINEES

Paul J. Bonavia

Chairman of the Board, President and Chief Executive Officer of UniSource Energy since January 1, 2009; Chairman of the Board, President and Chief Executive Officer of Tucson Electric Power Company ("TEP") , the principal subsidiary of UniSource Energy, since January 1, 2009; Chairman of the Board, President and Chief Executive Officer of UniSource Energy Services, Inc. ("UES"), a wholly-owned subsidiary of UniSource Energy, since January 1, 2009; former President of the Utilities Group of Xcel Energy, an electric and gas utility, from December 2005-December 2008; and former President of Commercial Enterprises of Xcel Energy from 2004 to December 2005. Board member since January 1, 2009. Age 57.

Lawrence J. Aldrich (2)(4)

President and Chief Executive Officer of University Physicians Healthcare, a healthcare organization, since January 2009; President of Aldrich Capital Company, an acquisition, management and consulting firm, since January 2007; Chief Operating Officer of The Critical Path Institute, a non-profit medical research company focusing in drug development, from January 2006 to December 2006; General Partner of Valley Ventures, LP, a venture capital company, from September 2002 to December 2005; Managing Director and Founder of Tucson Ventures, LLC, a venture capital company, from February 2000 to September 2002; Director of TEP and Millennium since 2000; and Director of UES since 2004. Board member since 2000. Age 56.

Barbara M. Baumann (1)(3)

President and Owner of Cross Creek Energy Corporation, a management consultant and investor company for oil and gas, since 2003; Director of St. Mary Land & Exploration since 2002; and Director of TEP since 2005. Board member since 2005. Age 53.

Larry W. Bickle (2)(3)

Retired private equity investor; Managing Director of Haddington Ventures, LLC, a private equity fund, from 1997 to 2007; Director of St. Mary Land & Exploration, an oil and gas production company, since 1995; Director of Millennium from 1998-2008; and Director of UES since 2004. Board member since 1998. Age 63.

Elizabeth T. Bilby (4)(5)

Retired President of Gourmet Products, Inc., an agricultural product marketing company; retired Director of Marketing of Green Valley Pecans, a pecan producer; Director of TEP since 1995; Director of Millennium from 1998-2008; and Director of UES since 2004. Board member since 1995. Age 69.

Harold W. Burlingame (2)(5)(6)

Former Executive Vice President of AT&T, a telecommunications company; Chairman of ORC Worldwide since December 2004; and Director of TEP since 1998. Board member since 1998. Age 68.

John L. Carter (1)(2)(3)(4)(5)(6)

Retired Executive Vice President and Chief Financial Officer of Burr Brown Corporation, a company that manufactured integrated circuits, in 1996; Director of Global Solar Energy since January 2007, Director of TEP since 1996; Director of Millennium from 1998-2008; Director of UES since 2004; and UniSource Energy Lead Director since 2005. Board member since 1996. Age 74.

Robert A. Elliott (3)(4)(6)

President and owner of The Elliott Accounting Group, an accounting firm, since 1983; Director and Corporate Secretary of Southern Arizona Community Bank since 1998; Television Analyst/Pre-game Show Co-host for Fox Sports Arizona, television broadcasting, since 1999; Chairman of the Board of Tucson Metropolitan Chamber of Commerce from 2002 to 2003; Treasurer of Tucson Urban League from 2002 to 2003; Chairman of the Board of Tucson Urban League from 2003 to 2004; Chairman of the Board of the Tucson Airport Authority from January 2006 to January 2007; and Director of TEP since May 2003. Board member since 2003. Age 53.

Daniel W. L. Fessler (1)(3)(6)

Professor Emeritus of the University of California; Of Counsel for the law firm of Holland & Knight from August 2003-January 2007; Partner in the law firm of LeBoeuf, Lamb, Greene & MacRae LLP from 1997 to 2003; previously served on the UniSource Energy and TEP boards of directors from 1998 to 2003; Managing Principal of Clear Energy Solutions, LLC since December 2004; and Director of TEP since 2005. Board member since 2005. Age 67.

Louise L. Francesconi (2)(4)

Retired President of Raytheon Missile Systems, a defense electronics corporation; Director of Stryker Corporation from July 2006, Director of Global Solar Energy from June 2008, Director of TEP since August 2008; and Director of UES since August 2008; Board member since August 2008. Age 56.

Warren Y. Jobe (1)(4)(6)

Certified Public Accountant (licensed, but not practicing); Senior Vice President of Southern Company, an electric service company, from 1998 to 2001; Director of WellPoint Health Networks, Inc. from 2001 to December 2004; Director of WellPoint, Inc. since December 2004; Trustee of RidgeWorth Funds since 2004; Director of TEP since 2001; and Director of Millennium from 2001 to 2003. Board member since 2001. Age 68.

Ramiro G. Peru (2)(4)

Executive Vice President and Chief Financial Officer of Swift Transportation, a trucking company, from June 2007 to December 2007, Executive Vice President and Chief Financial Officer of Phelps Dodge Corporation, a mining corporation, from 2004 to 2007; Director of WellPoint Health Networks, Inc. since 2003; Director of Southern Peru Copper Corporation from 2002 to 2004; and Director of University of Arizona Foundation since 2005. Board member since January 2008. Age 53.

Gregory A. Pivirotto (1)(3)

President and Chief Executive Officer and Director of University Medical Center Corporation, a hospital, since 1994; Certified Public Accountant since 1978; Director of Arizona Hospital & Healthcare Association from 1997 to 2005; and Director of Tucson Airport Authority since 2008; Board member since January 2008. Age 56.

Joaquin Ruiz (3)(5)

Professor of Geosciences, University of Arizona since 1983; Dean, College of Science, University of Arizona since 2000; Vice President of the Geological Society of America beginning in 2009; Associate Editor, "American Journal of Science" since 2005; Associate Editor, American Presidents Advisory Board of Research Corporation since 2005; Member, Human Resources Committee, American Geological Institute from 2000 to 2005 and 2009-2012; Member, Governing Board, Instituto Nacional de Astronomia, Optica y Electronica, Mexico since 2003; Board Member, Center to Improve Diversity in Earth Systems Sciences, Inc. since 2003; Member of Board of Earth Sciences, National Research Council of the National Academy of Sciences since 2005; TEP Board Member since 2005; and UES Board member since 2005. Board Member since 2005. Age 57.

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(1) Member of the Audit Committee.
(2) Member of the Compensation Committee.
(3) Member of the Corporate Governance and Nominating Committee.
(4) Member of the Finance Committee.
(5) Member of the Environmental, Safety and Security Committee.
(6) Member of the Corporate Development Committee.

The Board recommends that you vote "FOR" these nominees.

PROPOSAL TWO: RATIFICATION OF SELECTION OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Audit Committee has selected PricewaterhouseCoopers, LLP ("Pricewaterhouse") as the Company's Independent Registered Public Accounting Firm for the fiscal year 2009, and the Board is asking the shareholders to ratify that selection. Although current law, rules, and regulations, as well as the charter of the Audit Committee, require the Audit Committee to engage, retain, and supervise the Company's Independent Registered Public Accounting Firm, the Board considers the selection of the Independent Registered Public Accounting Firm to be an important matter of shareholder concern and is submitting the selection of Pricewaterhouse for ratification by shareholders as a matter of good corporate practice.

Under Arizona law, if a quorum of shareholders is present at the Meeting, the ratification of the selection of PricewaterhouseCoopers as Independent Registered Public Accounting Firm for 2009 will require that the votes cast in favor of its ratification exceed the votes cast against its ratification. Abstentions and broker non-votes are counted for purposes of determining whether a quorum exists at the Meeting but are not counted and have no effect on the results of the vote for Independent Registered Public Accounting Firm.

The Board recommends that you vote "FOR" the ratification of the selection of the Independent Registered Public Accounting Firm.

COMPENSATION DISCUSSION AND ANALYSIS

The following Compensation Discussion and Analysis contains statements regarding future individual and Company performance targets and goals. These targets and goals are disclosed in the limited context of UniSource Energy's compensation programs and should not be understood to be statements of management's estimates of results or other guidance. UniSource Energy specifically cautions investors not to apply these statements to other contexts.

EXECUTIVE SUMMARY

At UniSource Energy, our mission is to deliver safe, reliable service and value to customers and shareholders alike. Our strategy includes enhancing shareholder value, maintaining customer satisfaction, expanding our role in the community, meeting environmental challenges and providing for our employees' development and well-being. We believe that our executive compensation program must align the interests of all our executive officers with this strategy to achieve our objectives.

UniSource Energy provides a balanced total compensation program that includes four components: base salary, short-term performance-based incentive, long-term performance-based incentive and other employee benefits.

In 2008, our continuing operations consisted mainly of the business conducted in three primary segments — TEP, UNS Gas, Inc., and UNS Electric, Inc. TEP, an electric utility, has provided electric service to the community of Tucson, Arizona, for more than 100 years. UNS Gas and UNS Electric provide natural gas and electric service in northern and southern Arizona. UNS Gas and UNS Electric are operating subsdiaries of UES, which was established in 2003 to oversee gas and electric properties acquired that year from Citizens Communications.

A significant part of our executive officers' compensation is based on our success in achieving annual corporate goals. These goals are designed to align the interest of our executive officers and all non-bargaining unit employees with our Company's strategy. The objectives of this incentive program and elements of compensation are discussed in detail below.

In 2008, our pursuit of these goals achieved mixed results. UniSource Energy demonstrated excellent performance relative to its cost containment, core business and customer service goals. The year was marked by a number of key accomplishments, including strong service reliability and customer service metrics and the approval of new rates for TEP and UNS Electric. However, two of the Company's three financial goals were not met. UniSource Energy's 2008 results were negatively impacted by higher fuel and purchased power expenses and other cost increases related to power plant maintenance and outages. Customer growth also slowed considerably at both TEP and UES compared to prior years and is expected to remain depressed through 2009 due to economic conditions.

In 2009, TEP will be operating under new rates approved in November 2008 by the Arizona Corporation Commission ("ACC"). The rates, which took effect in December 2008, represent a six-percent increase over the previous base rates and include a new Purchased Power and Fuel Adjustment Clause that will allow the utility to pass along changes in energy costs to customers.

The TEP rate order was the culmination of a multi-year effort led by James S. Pignatelli, who retired as Chairman, President and CEO of UniSource Energy at year's end. He was succeeded by Paul J. Bonavia, whose appointment as Chairman, President and CEO was effective January 1, 2009.

The objectives of UniSource Energy's executive compensation program and the elements of compensation are discussed in detail in the sections to follow.

COMPENSATION PHILOSOPHY

Objectives of the Compensation Program

We base our executive compensation policies and decisions with respect to our Named Executives on the achievement of the following objectives:

1. Attracting, motivating and retaining highly-skilled executives;
2. Linking the payment of compensation to the achievement of critical short- and long-term financial and strategic objectives, creation of shareholder value and provision of safe, reliable and economically available electric and gas service; and aligning performance objectives of management with those of other Company employees by using similar performance measures;
3. Aligning the interests of management with those of our stakeholders and encouraging management to think and act like owners, taking into account the interests of the public that the Company serves;
4. Maximizing the financial efficiency of the compensation program to avoid unnecessary tax, accounting and cash flow costs; and
5. Encouraging management to achieve outstanding results through appropriate means by delivering compensation in a manner consistent with established and emerging corporate governance best practices.

In support of the above objectives, UniSource Energy provides a balanced total compensation program that consists of four components:

- base salary;
- short-term performance-based incentive compensation;
- long-term performance-based incentive compensation; and
- benefits and perquisites.

Decisions made regarding each component of pay are considered in the context of each officer's total compensation. For example, if a decision is made to increase an executive's base salary, the resultant impact on short- and long-term performance-based incentive compensation and total compensation levels are evaluated relative to competitive practice (see "Benchmarking" discussion below). We do not consider the value of outstanding equity awards in setting annual total compensation opportunities as we believe that outstanding equity awards represent compensation for past service.

Each of these components is described in more detail below and in the narrative and footnotes to the supporting tables. The following illustrates how the above objectives are reflected in our compensation program:

Attracting, Retaining and Motivating Executive Talent

In support of our objective to attract, retain and motivate highly-skilled employees, we provide our Named Executives with compensation packages that are competitive with those offered by other electric and gas service companies of comparable size and complexity and/or electric and gas service companies thought to be competitors for executive talent.

The Compensation Committee generally targets base salary and short-term incentive opportunities, as well as the allocation among those elements of compensation for the Named Executives, at the median market rates of selected comparable companies identified below under the "Benchmarking" section. Long-term incentive opportunities are targeted at the 75th percentile of such market rates. Target compensation for individual executives range above or below those benchmarks based on a variety of factors, including each executive's skill set and experience relative to the general market, the importance of the position to the Company and the difficulty of replacing the executive, and the executive's past and expected future contribution to our success. Overall, total direct compensation for 2008 (i.e., salary, 2008 target PEP awards, and present value of 2008 long-term incentive awards) for the Named Executives fell between the median and 75th percentile of market rates.

In addition to providing competitive direct compensation opportunities, the Company also provides certain indirect compensation and benefits programs that are intended to assist in attracting and retaining high quality executives. These programs include pension and retirement programs and are described in more detail below and in the narratives that accompany the tables that follow this Compensation Discussion and Analysis section.

Linking Compensation to Performance

Our compensation program seeks to link the actual compensation earned by our Named Executives to their performance and that of the Company. We achieve this goal primarily through two elements of our compensation package: (i) short-term cash awards and (ii) equity-based compensation. To ensure that the senior executives are held most accountable for achieving our financial, operational and strategic objectives and for creating shareholder value, we believe that the percentage of pay at risk should increase with the level of responsibility within the Company. The target amounts of performance-based pay programs (i.e., cash incentive and equity-based compensation) comprise approximately 55% to 65% of the total direct compensation opportunity for our Named Executives. Of the performance-based compensation, approximately 30-45% is short-term and 55-70% is long-term. Placing a greater emphasis on long-term performance-based compensation encourages executives to focus on the long-term impact of their actions. Non-variable compensation, such as salary and perquisites, is de-emphasized in the total compensation program to reinforce the linkage between compensation and performance.

Aligning the Interests of our Named Executive Officers with Stakeholders

Our compensation program also seeks to align the interests of our Named Executives with those of our key stakeholders, including customers, employees and shareholders. We use the short-term incentive compensation component to focus the Named Executives on the importance of providing safe and reliable customer service, creating a safe work environment for our employees and improving financial performance by linking a significant portion of their short-term cash incentive compensation to achievement of these objectives. We primarily rely on the equity compensation element of our compensation package to align the interests of the Named Executives with those of shareholders through a mix of stock options and stock awards that vest based on the achievement of performance goals set by the Compensation Committee. We also encourage senior executives to accumulate a substantial stake in the Company.

Maximizing the Financial Efficiency of the Program

In structuring the total compensation package for our Named Executives, the Compensation Committee evaluates the accounting cost, cash flow implications and tax deductibility of compensation to mitigate financial inefficiencies to the greatest extent possible. For instance, as part of this process, the Compensation Committee evaluates whether compensation costs are fixed or variable and places a heavier weighting on variable pay elements to calibrate expense with the achievement of operating performance objectives and delivery of value to shareholders. In addition, the Compensation Committee takes into account the objective of having the incentive-based compensation components qualify for tax deductibility under Section 162(m) of the Internal Revenue Code, as amended (the "Code"). See discussion under "Impact of Regulatory Requirements" on page 23. The Compensation Committee also considers the cash flow and share dilution implications of cash versus equity-based incentive plans.

Adhering to Corporate Governance Best Practices

The Compensation Committee seeks to continually update the executive officer compensation program to reflect corporate governance best practices. For example, the Compensation Committee has established formal stock ownership guidelines that encourage each Named Executive to accumulate a meaningful amount of Company stock. Additionally, equity-based awards contain a "double-trigger" vesting provision, which provides for accelerated vesting in the event of a future change in control only if the executive is adversely impacted by the transaction. See discussion under "Potential Payments Upon Termination or Change in Control".

Benchmarking

The Compensation Committee considers the following factors for purposes of establishing salaries and variable compensation opportunities: (i) the competitive environment for Named Executives and what relevant competitors pay, and (ii) the need to provide each element of compensation and the amounts targeted and delivered.

To provide a foundation for the executive compensation program, UniSource Energy periodically benchmarks its named executive officers' compensation levels and practices against a peer group of companies intended to represent our competitors for business and talent. The peer group, which is reviewed periodically, includes the 17 electric and gas utility companies named below that are comparable to UniSource Energy in terms of size as measured by annual revenues and market capitalization. Except as described below, this group is the same peer group for 2008 that was used in prior competitive analyses, with the exception of Otter Trail Power Company and Southern Union Co., which were omitted from the peer group for 2008 due to differences in business models, and with the exception of North Western Corp., Piedmont Natural Gas Co., Pinnacle West Capital Corp., and Portland General Electric Co., which were included for 2008 due to similarity of business models, similar size, or because they were thought to be a competitor for executive talent. A review of UniSource Energy's executive compensation levels relative to the peer group was conducted in October 2008, and a review of aggregate long-term incentive cost and share usage practices relative to the peer group was last conducted in October 2007. UniSource Energy's 2007 revenues were between the 25th percentile and the median of the peer companies; market capitalization as of September 2008 was between the 25th percentile and the median of the peer companies.

2008 Peer Group:

AGL Resources Inc.	DPL Inc.	North Western Corp.	Portland General Electric Co.
Avista Corp.	El Paso Electric Co.	Piedmont Natural Gas Co.	South Jersey Industries Inc.
CH Energy Group Inc.	IDACORP Inc.	Pinnacle West Capital Corp.	Southwest Gas Corp.
Cleco Corporation	Northwest Natural Gas Co.	PNM Resources Inc.	UIL Holdings Corp.
			Westar Energy Inc.

The benchmark information is supplemented annually with information from Frederic W. Cook and Co., Inc., the independent consultant retained by the Compensation Committee, relating to general market trends, changes in regulatory requirements related to executive compensation and emerging best practices in corporate governance. See discussion relating to compensation consultant under "Compensation Consultant" on page 43.

ELEMENTS OF COMPENSATION

Base Salary

Base salary is used to provide each Named Executive a set amount of money during the year with the expectation that he or she will perform his or her responsibilities to the best of his or her ability and in the best interests of our Company. We believe that competitive base salaries are necessary to attract and retain executive talent critical to achieving the Company's business goals. In general, our Named Executives' base salaries are targeted to the median of the peer group described above. However, individual salaries can and do vary from the benchmark median data based on such factors as individual performance, potential for future advancement, the importance of the executive's position to the Company and the difficulty of replacement, current responsibilities, length of time in the current position, and, for recently hired executives, their prior compensation packages. Currently, all of our Named Executives' salaries, other than the CEO's, are within 10 percent of the benchmark median. For 2008, the CEO's salary approximated the 75th percentile in recognition of his leadership through the years, contributions to the growth of the Company, long tenure and strong performance.

Increases to Named Executives' base salaries are considered annually by the Compensation Committee. In approving base pay increases for Named Executives other than the CEO, the Compensation Committee also considers recommendations made by the CEO.

In December 2008, the Compensation Committee approved base salary increases for the Named Executives (other than Mr. Pignatelli, who retired effective as of January 1, 2009), for 2009. The following table indicates the Named Executives' base salaries for 2008 and 2009:

Name	*2008 Base Pay*	*Approved 2009 Base Pay*
James S. Pignatelli	$726,000	Not applicable
Kevin P. Larson	$316,000	$327,000
Michael J. DeConcini	$321,000	$332,200
Raymond S. Heyman	$316,000	$327,000
Karen G. Kissinger	$249,000	$257,400

The salary increases for the Named Executives were consistent with salary increases as a percent of salary for other non-represented employees.

Short-Term Incentive Compensation (Cash Awards)

The Compensation Committee provides for short-term incentive compensation in the form of cash awards under the Performance Enhancement Plan ("PEP") in order to link a significant portion of the Named Executives' annual compensation to the Company's annual financial and operational performance.

Each year, before the end of the first quarter, the Compensation Committee establishes performance objectives that must be met in whole or in part before the Company pays PEP awards. The Compensation Committee generally attempts to align the target opportunity for each Named Executive with the median rate for equivalent positions at the benchmark companies. In 2008, the target incentive opportunity for the Named Executives ranged from 40% to 80% of base salary, depending on position. As described more fully below, the actual amounts paid depend on the achievement of specified performance objectives, and could range from 50% of the target award upon achievement of threshold performance to 150% of the target award upon achievement of outstanding performance. The Compensation Committee has the discretion to increase, reduce or eliminate a PEP award regardless of whether the performance goals applicable to the Named Executive's incentive award have been achieved.

Financial and Operating Performance Objectives-2008

The PEP performance targets and weighting are based on factors that are essential for the long-term success of the Company and are identical to the performance objectives used in the Company's performance plan for non-represented employees. In 2008, the financial and operating objectives were diluted earnings per share ("EPS"), operating cash flow, cost containment ("O&M") and customer service and core business goals relating to customer service, regulatory, reliability, project implementation and safety matters.

The measures and individual weightings for the 2008 PEP were selected by the Compensation Committee to ensure an appropriate focus on profitable growth, cash flow generation and expense control, as well as operational and customer service excellence. We think that this approach encourages all employees to work toward common goals that are in the interests of our various stakeholders including customers, employees and shareholders.

The Compensation Committee selected diluted EPS as a performance measure to work in tandem with the Company's reporting metrics to the financial community. In 2008, 20% of the PEP award was based on attaining the diluted EPS targets, 20% of the PEP award was based on attaining operating cash flow targets, 20% was based on keeping O&M costs within a specified range, and the remaining 40% was based on the achievement of our customer service and core business goals. The cash flow target, which was not a performance measure in 2007, was selected in 2008 as a performance measure to focus employees on generating cash for the Company during 2008 and in future years.

In developing the PEP performance targets, the Chief Financial Officer ("CFO") of the Company, with assistance from other personnel, compiles relevant data and makes recommendations to the Compensation Committee for a particular year, but the Compensation Committee ultimately determines the performance objectives that are adopted.

The 2008 quantitative performance objectives included:

2008 Performance Objectives	Threshold	Target	Outstanding
Diluted EPS	$ 1.70 per share	$ 1.95 per share	$ 2.20 per share
Operating Cash Flow	$ 280 million	$ 298 million	$ 315 million
O&M	$ 294 million	$ 289 million	$ 284 million

In addition, the 2008 customer service and core business goals included:

- Averaging customer service response time at or below 3 minutes;
- Volunteering community service of at least 38,000 hours by employees;
- Completing specific departmental project goals;
- Achieving various operational reliability goals; and
- Maintaining OSHA incident rates at or below industry average and implementing a safety awareness program.

Short-Term Incentive Award to the CEO

Because the CEO's total compensation could exceed $1 million, section 162(m) of the Internal Revenue Code ("Section 162(m)") would deny the Company a tax deduction for the excess over $1 million, unless that excess compensation qualified as performance-based compensation. To comply with the performance-based compensation requirements, and also allow the Compensation Committee to retain some discretion to reduce the PEP award, if appropriate, the Compensation Committee used a different approach from that described above for the Named Executives and other employees, requiring two separate steps, to calculate the CEO's short-term incentive award.

The first step involved the 2006 Omnibus Stock and Incentive Plan (the "2006 Omnibus Plan"), which permits payment of cash awards up to $2 million. For the CEO's short-term incentive award to qualify as performance-based compensation, Section 162(m) requires that the award be payable solely upon the attainment of performance goals. If the performance goals are achieved, Section 162(m) would permit the Compensation Committee to pay the amount specified at the time of the award or to pay any lesser amount, but would not allow payment of any greater amount. For the CEO's short-term incentive award, the Compensation Committee established a minimum attainment of cash from operations of at least $256 million for 2008, which, if achieved, would allow the Committee to pay the CEO the $2 million maximum permitted by the 2006 Omnibus Plan or any lesser amount; however, if the Company failed to achieve $256 million of cash from operations, the CEO would not be entitled to any short-term incentive award payment, regardless of the achievement of other PEP performance objectives as described above. In this respect, the CEO's performance objective differed significantly from objectives set for the awards to the other Named Executives. The CEO's award had an absolute minimum performance level that must have been achieved before the CEO received any payment, whereas if the Company failed to achieve the minimum performance on the operating cash flow objective set under the PEP, the other Named Executives could have still received a payment based on the attainment of the remaining performance objectives. Solely for purposes of this first step of determining the CEO's short-term incentive award, the Committee felt it was appropriate to set the CEO's operating cash flow performance objective slightly below the operating cash flow threshold used for the other Named Executives, because of the increased importance of the CEO's operating cash flow target, the increased risk related to that target, and the desire to comply with the performance-based compensation requirement of Code Section 162(m).

The second step for determining the CEO's short-term incentive award involved applying the PEP performance objectives and methodology. Once the Company achieved the minimum performance objective established pursuant to the 2006 Omnibus Plan for the CEO to receive any payment, the amount of the CEO's payment, including whether the CEO received the minimum, target or maximum amount as a percentage of base salary, would be determined using the same PEP performance objectives and methodology as described above for the other Named Executives.

As described above, the range of actual payouts would in all cases be less than the maximum amount permitted by the 2006 Omnibus Plan and would satisfy the performance-based compensation requirements of Section 162(m). Using the PEP guidelines, the Compensation Committee determined that the CEO's threshold, target and maximum annual incentive awards should be $290,400 (50% of his target award), $580,800 (100% of his target award and 80% of his base salary), and $871,200 (150% of his target award), respectively.

PEP Results

In 2008, the Company achieved $0.39 per share of diluted EPS, which was below the threshold level of performance of $1.70 per share. The Company achieved operating cash flow for 2008 of $277 million, which was also below the threshold level of performance of $280 million. In 2008, the Company achieved an O&M spending level for 2008 of $286.1 million, as shown in Table A below, which, because lower O&M spending represented better performance, was better than the target level of performance.

Table A, below, reflects the O&M cost containment goal, which ranged from $294 million (threshold) to $284 million (outstanding), and the corresponding payout levels, which ranged from 50% to 150% of the target award, as well as the O&M spending level achieved for 2008. O&M spending must have been less than $294 million to produce a payout; O&M spending in excess of $294 million would not have paid any amount for that performance target. According to the guidelines set by the Compensation Committee at the time of the award, which required interpolating on a straight-line basis, the achievement of the better than the target level of performance of the O&M spending target resulted in a payout level of 129% of the target amount for that factor.

Table A

										286.1		
O&M	Range ($ Millions)	294	293	292	291	290	289	288	287	286	285	284
Payout	Payout %	50%	60%	70%	80%	90%	100%	110%	120%	130%	140%	150%
										129%		

Table B, below, reflects the performance on the customer service and core business goals, which ranged from earning 200 points (threshold) to 500 points (outstanding), and the corresponding payout levels, which ranged from 50% to 150% of the target award. A greater number of points earned from the achievement of each goal, resulted in a greater level of performance. As shown in the table below, during 2008 the Company achieved 490 points from the customer service and core business goals.

Table B

					490
Core Business & Customer Service	Range (Points)	200	300	400	500
Payout	Payout %	50%	83%	117%	150%
					146%

The Company had five major categories of customer service and core business goals: Customer Service (which is generally discussed above), Reliability (which pertains to the operational reliability of the generation, transmission and distribution systems), Project Implementation (which pertain to six specific key departmental goals), Safety (which are discussed above), and Regulatory (which pertain to rate cases and compliance with certain regulatory requirements by subsidiary companies, as discussed below). Each category of goals earned points; Regulatory was worth 250 points (50% of the total points possible), with the other categories worth 62.5 points each. Each category of goals contains several sub-goals that share the total points available in each category. Quantitative and qualitative goals are included, and points are accumulated based on achievement of each sub-goal.

In the Regulatory category, there were four sub-goals, which included: (i) obtaining a rate case settlement agreement with the ACC for TEP, one of our electric subsidiaries; (ii) filing and advancing a rate case with the ACC for our gas subsidiary; (iii) obtaining approval from the ACC for the Renewable Energy Standard Tariff implementation, which satisfies Arizona-specific regulations; and (iv) completion by UNS Electric, Inc., which is also one of our electric subsidiaries, of its rate case filed with the ACC.

All Regulatory goals were achieved in 2008, contributing 250 points to the core and customer service business goals. All Safety, Customer Service, Reliability, and five out of the six Project Implementation goals were achieved. In 2008, the Company earned a total of 490 points for the customer service and core business goals, which was close to an outstanding level of performance. According to the guidelines set by the Compensation Committee at the time of the award, which required interpolating on a straight-line basis, the achievement of the these goals resulted in a payout level of 146% of the target amount for that factor.

Overall, these results produced total weighted performance for 2008 of 84.3% of target performance.

The Compensation Committee agreed and approved a PEP payout of 84.3% of target awards for Named Executives other than Mr. Pignatelli.

Mr. Pignatelli was eligible for a payment on account of his annual incentive award because the Company exceeded the minimum threshold of $256 million operating cash flow necessary for him to receive a payment. Having confirmed that Mr. Pignatelli was eligible for a payment, the Compensation Committee used the methodology described above to determine that Mr. Pignatelli was entitled to receive a payment of $500,000, or 86.1% of his target award. This payment, as a percent of the target award, was slightly higher than the payments to other Named Executives and reflects Committee use of discretion to recognize Mr. Pignatelli's leadership with respect to strategic initiatives and executive transition issues.

Long-Term Incentive Compensation (Equity Awards)

We believe that equity awards, in tandem with our executive stock ownership guidelines discussed below, encourage ownership of Company stock by executive officers and hold executive officers accountable for the long-term impact of their actions, which in turn aligns the interest of those officers with the interest of our shareholders. In addition, the vesting provisions applicable to the awards encourage a focus on long-term operating performance, link compensation expense to the achievement of multi-year financial results and help to retain executive officers.

The long-term incentive opportunity for each Named Executive is based on a multiple of salary. The current long-term incentive multiple, which is 100% of base salary for each Named Executive, was established in 2003 to retain the executives in light of a then pending merger. The value of the Named Executives' long-term incentive multiples, which is generally consistent with the median to 75th percentile of benchmark practice, has been maintained for the Named Executives to strengthen the retention value of the compensation program following the termination of the proposed merger transaction in 2004 and to avoid a reduction in Named Executives' compensation, which would allow some of the Named Executives to terminate employment for "good reason" and receive change in control severance benefits. See "Elements of Post-Employment Compensation – Termination and Change in Control" for greater detail. While Mr. Heyman is not covered under a change in control agreement, the Compensation Committee set his long-term incentive opportunity at 100% of salary to advance internal pay equity with the other Named Executives with comparable responsibility levels. Mr. Pignatelli's long-term incentive opportunity of 100% of salary is below the targeted 75th percentile and his total direct compensation falls between the median and 75th percentile.

In developing the long-term performance targets, the CFO of the Company compiles relevant data and makes recommendations to the Compensation Committee, but the Compensation Committee ultimately determines the performance objectives that are adopted for the applicable long-term plan.

For 2008, management recommended and the Compensation Committee approved long-term incentive awards consisting of equally weighted stock options and performance shares with earnout tied to total shareholder return

("TSR"). Given the difficulty in projecting the outcome of the TEP rate case, which occurred in 2008, and the unpredictable impact of the TEP rate case on diluted EPS, the Compensation Committee decided to use TSR as the performance metric for 2008, rather than cumulative diluted EPS. TSR was selected as the performance objective as it rewards executives for creating value in excess of a broad index of utilities. We believe that this long-term incentive approach consisting of stock options and TSR-based performance shares focuses the Named Executives on increasing both absolute and relative shareholder value creation. Moreover, stock option grants and performance share awards are intended to qualify as performance-based compensation under Section 162(m) of the Code, which is tax deductible by the Company.

Stock Option Grants

Options are designed, in part, to reward longer term success in Company performance that is reflected in increases in share price. The Company's options, granted with an exercise price equal to the fair market value on the date of grant, help focus executives on long-term growth. In addition, options are intended to help retain key employees because they become exercisable in one-third increments over a three year period. The three-year incremental vesting also keeps executives focused on long-term performance.

Performance Share Awards

Performance shares are designed, in part, to reward achievement of financial performance objectives and/or shareholder value objectives.

2008 Program

The 2008 performance share awards are tied to TSR, relative to the Edison Electric Institute index, over a three-year performance period, commencing in 2008 and ending in 2010. The 2008 performance share criteria were established at the beginning of 2008 and are set forth in the following table.

PERFORMANCE CRITERIA

TSR Percentile Rank	Payout as a Percent of Target Award
75^{th} percentile and above	150%
60^{th} percentile – 74^{th} percentile	125%
50^{th} percentile – 59^{th} percentile	100%
40^{th} percentile – 49^{th} percentile	75%
35^{th} percentile – 39^{th} percentile	50%
Below 35^{th} percentile	0%

2006 Program

The 2006 performance share awards were tied to the achievement of Basic EPS (defined as EPS applied to undiluted outstanding shares), and operating cash flow goals over the 2006-2008 performance period.

The cumulative Basic EPS for the 2006-2008 performance period was $3.96 per share, which is less than threshold, and resulted in no payment on the Basic EPS goal. The cumulative operating cash flow was $882.3 million and resulted in a 33% operating cash flow payout. See the "Outstanding Equity Awards Table" on pages 29-31 for the number and market value of unearned share awards for each of the Named Executives.

Table C, below, reflects the cumulative Basic EPS goal, which ranged from $5.80 per share (threshold) to $6.38 per share (outstanding), and the corresponding payout levels, which ranged from 25% to 75% of the target award. As noted above, the cumulative Basic EPS for the three year period comprising 2006-2008 was less than the threshold level, as shown on the table below; therefore, there was no payout on the Basic EPS goal.

Table C

EPS - Basic	Range	$3.96	$5.80	$6.07	$6.38
	Payout %	0%	25%	50%	75%

Table D, below, reflects the operating cash flows goals, which ranged from $879.6 million (threshold) to $901.1 million (outstanding), and the corresponding payout levels which ranged from 25% to 75% of the target award. As shown on the table below, the Company achieved a cumulative operating cash flows level of $882.3 million, which resulted in a payout level of 33% of the target amount for that factor.

Table D

Cash Flow	Range ($ Millions)	$879.6	$882.3	$888.3	$901.1
	Payout %	25%	33%	50%	75%

The targets and goals discussed above are disclosed in the limited context of UniSource Energy's compensation programs and should not be understood to be statements of management's estimates of results or other guidance. UniSource Energy specifically cautions investors not to apply these statements to other contexts.

Equity Grant Timing and Practice

Generally, during the first quarter following the close of a fiscal year, the Compensation Committee approves the long-term incentive awards to be granted for the upcoming year, including the type of equity to be granted, as well as the size of the awards for Named Executives. In determining the type and aggregate size of awards to be provided, as well as the performance metrics that will apply, the Compensation Committee considers the strategic goals of the Company, trends in corporate governance, accounting impact, tax deductibility, cash flow considerations, the impact on EPS and the number of shares that would be required to be allocated for the award and the resulting impact to shareholders. When the Compensation Committee approves grants of plan-based equity awards, the exercise price is set at the market closing price of UniSource Energy common stock on the date that the grant is made. Awards are not coordinated with the release of material non-public information.

In addition, the Company does not typically provide for off-cycle stock option grants and has no specific number of shares under the 2006 Omnibus Plan set aside for such grants. However, occasionally in connection with a new hire of an executive, such a grant may be made to the extent approved by the Compensation Committee. The exercise price of any off-cycle option granted to a newly hired executive will be the closing market price on the date that the Compensation Committee approves any such award, consistent with the pricing practices associated with on-cycle plan-based equity awards.

STOCK OWNERSHIP POLICY

To further support our objective of aligning management and shareholder interests, the Company maintains a formal stock ownership policy, which encourages all officers to accumulate a substantial ownership stake in Company shares. The policy has the following key features:

- Participants are encouraged to accumulate Company shares with a target value of a multiple of their base salary, ranging from one times base salary for Vice Presidents, three times for senior Vice Presidents and five times for our CEO.

- If a participant has not yet reached the applicable target ownership requirement, he or she is expected to retain a portion of the net after-tax shares acquired from any stock option exercise, vesting of restricted stock or payments related to the performance share program. The applicable retention rates are 100% for the CEO, 50% for Named Executives who are senior Vice Presidents and 25% for the other Vice Presidents.

- Unexercised stock options, unvested stock options and unearned performance shares do not count towards meeting the ownership guidelines.

Annually, management provides a report to the Compensation Committee regarding the number and value of the shares held by each officer subject to the guidelines. As of December 31, 2008, all of the Named Executives who were hired before 2005, including the CEO, have achieved their target ownership level. Raymond S. Heyman, who was hired after 2005, is making progress toward meeting the guideline.

OTHER COMPENSATION

Perquisites

The Company provides Named Executives with limited personal benefits and perquisites. These are not tied to any formal individual or Company performance criteria but are intended to enhance the attraction and overall retention value of the executive compensation program and to be comparable to similar benefits provided to executives and other key personnel in other similar companies in the industry. As a benefit, the Company from time to time reimburses certain executives for business or similar social club initiation fees and periodic special assessments. The Company also reimburses executives for the travel expenses of their spouses incurred in connection with the annual Board strategic retreat. The Company also has a policy of either directly paying or reimbursing certain executives for certain of their relocation costs, since this is a common benefit offered in the market and an additional means of attracting executives. None of our Named Executives benefited from the relocation policy during 2008. For identification of specific perquisites and associated values, refer to the "Summary Compensation Table" on page 25.

Retirement Benefits

Our Named Executives are also eligible to participate in certain employee benefits plans and arrangements offered by the Company. These include the Tucson Electric Power Company 401(k) Plan, the Tucson Electric Power Company Salaried Employees Retirement Plan (the "Retirement Plan"), the Tucson Electric Power Company Excess Benefit Plan (the "Excess Benefit Plan") and the Management and Directors Deferred Compensation Plan (the "DCP"). A description of the pension and other retirement plans is provided under "Elements of Post-Employment Compensation-Retirement and Other Benefits," below.

ELEMENTS OF POST-EMPLOYMENT COMPENSATION

Termination and Change in Control

In 1998, TEP, a wholly owned subsidiary of the Company, entered into Change in Control Agreements ("Change in Control Agreements" or "Agreements") with all of the then Named Executives to help keep them focused on their work responsibilities during the uncertainty that accompanies a change in control, to provide benefits for a period of time following certain terminations of employment after a change in control event or transaction and to help us attract and retain key personnel. Some of these Agreements remain in effect until 2010. See discussion preceding the "Potential Payments Upon Termination or Change in Control Table" on page 34.

Retirement and Other Benefits

Benefits Generally

The Company offers retirement and other core benefits to its employees, including executive officers, in order to provide them with a reasonable level of financial support in the event of illness or injury and to enhance productivity and job satisfaction. The benefits are the same for all employees and executive officers and include medical and dental coverage, disability insurance and life insurance. In addition, the Tucson Electric Power Company 401(k) Plan and the Retirement Plan provide a reasonable level of retirement income reflecting employees' careers with the Company. All employees, including executive officers, participate in these plans; the cost of these benefits (other than the Retirement Plan) is partially borne by the employee, including each executive officer. To the extent that any officer's retirement benefit exceeds Internal Revenue Service ("IRS") limits for amounts that can be paid through a qualified plan, the Company also offers non-qualified retirement plans, including the Excess Benefit Plan and the DCP. These plans provide only the difference between the calculated benefits and the IRS limits. Benefits under the Excess Benefit Plan are provided to officers but, with limited exceptions, are not generally available to other employees. These benefits are not tied to any formal individual or Company performance criteria but are intended to enhance the attraction and retention value of the executive compensation program and are consistent with similar competitive compensation benefits made available to executives in the industry. We believe the DCP assists with our attraction and retention objectives since it provides an industry-competitive and tax-efficient benefit to our executives. The DCP is not funded by the Company and participants have an unsecured contractual commitment by the Company to pay amounts owed under the DCP. For more information on retirement and certain related benefits, see the discussion following the "Pension Benefits Table" on page 33 and the "Non-Qualified Deferred Compensation Table" on page 34.

IMPACT OF REGULATORY REQUIREMENTS

Under Section 162(m) of the Code, compensation paid to the CEO and to certain other most highly compensated executives in excess of $1,000,000 annually is not deductible for federal income tax purposes unless the compensation is awarded under a performance-based plan approved by the shareholders, and satisfies certain other requirements. To the extent that the Company complies with the performance-based compensation provision of Section 162(m), the awards granted to the CEO and other Named Executives are tax deductible by the Company. The Company believes that all executive compensation earned in 2008 will be tax deductible.

The Compensation Committee believes that it is in the best interest of the Company to receive maximum tax deductibility for compensation paid to the Company's Named Executives, although to maintain flexibility in compensating Named Executives in a manner designed to promote varying corporate goals, the Compensation Committee may award compensation that is not fully deductible under certain circumstances. The Company's compensation plans reflect the Compensation Committee's intent and general practice to pay compensation that the Company can deduct for purposes of federal income tax. Executive compensation decisions, however, are multifaceted. The Compensation Committee reserves the right to pay amounts that are not tax deductible to meet the design goals of our executive compensation program.

The Compensation Committee also considers other financial implications when developing and implementing the Company's compensation program, including accounting costs, cash flow impact and potential share dilution.

COMPENSATION COMMITTEE REPORT ON EXECUTIVE COMPENSATION

The Compensation Committee has reviewed and discussed with management the "Compensation Discussion and Analysis" section required by Item 402(b) of SEC Regulation S-K and contained in this Proxy Statement. Based on such review and discussions, the Compensation Committee recommended to the Board that the "Compensation Discussion and Analysis" section be included in the Company's annual report on Form 10-K for the year ended December 31, 2008 and the 2009 Proxy Statement.

Respectfully submitted,

THE COMPENSATION COMMITTEE

Harold W. Burlingame, Chair
Lawrence J. Aldrich
Larry W. Bickle
John L. Carter
Louise L. Francesconi
Ramiro G. Peru

SUMMARY COMPENSATION TABLE—2008

The following table sets forth summary compensation information for the years ended December 31, 2006, December 31, 2007, and December 31, 2008 for our CEO, our CFO and three other most highly compensated Named Executives:

Name and Principal Position	Year ($)	Salary ($)	Stock Awards ($)(1)	Option Awards ($)(2)	Non-Equity Incentive Plan Compensation ($)(3)	Change in Pension Value and Non-Qualified Deferred Compensation Earnings ($)(4)	All Other Compensation ($)(5)	Total ($)
James S. Pignatelli Chairman, President and Chief Executive Officer	2008	724,689	98,305	348,790	500,000	793,548	13,532	2,478,864
	2007	694,438	97,755	319,336	791,000	0	262,236	2,164,765
	2006	666,923	95,476	339,742	867,500	210,550	17,646	2,197,837
Kevin P. Larson Senior Vice President and Chief Financial Officer	2008	315,499	46,397	137,107	132,700	208,912	14,366	854,981
	2007	299,814	62,731	85,372	237,632	0	49,237	734,786
	2006	288,462	41,317	32,671	259,184	74,313	15,352	711,299
Michael J. DeConcini Senior Vice President and Chief Operating Officer, Transmission and Distribution	2008	320,112	46,910	137,776	134,800	161,064	15,485	816,147
	2007	300,178	62,731	85,372	243,608	0	74,960	766,849
	2006	288,462	41,317	32,671	265,196	38,573	14,768	680,987
Raymond S. Heyman Senior Vice President and General Counsel	2008	319,949	46,397	224,702	132,700	159,468	14,408	897,624
	2007	304,077	62,731	208,484	146,000	43,651	14,183	779,126
	2006	288,462	41,317	155,783	167,000	65,352	14,020	731,934
Karen G. Kissinger Vice President, Controller and Chief Compliance Officer	2008	248,493	36,536	124,994	83,700	205,525	11,182	710,430
	2007	236,731	49,647	67,598	179,648	0	13,011	546,635

(1) The amounts included in the "Stock Awards" column represent the compensation expense recognized by the Company for performance share awards during 2006, 2007 and 2008, calculated in accordance with Statement of Financial Accounting Standards share based payment (revised 2004) ("FAS 123R"). The Company's FAS 123R assumptions used in these calculations are set forth on pages 149-152 of our annual report on Form 10-K filed with the SEC on March 2, 2009, and available on the Company's website at www.UNS.com.

(2) The amounts included in the "Option Awards" column represent the compensation expense recognized by the Company for stock option awards granted to the Named Executives during 2006, 2007 and 2008, and a 2005 stock option award to Mr. Heyman, calculated in accordance with FAS 123R. The Company's FAS 123R assumptions used in these calculations are set forth on pages 149-152 of our annual report on Form 10-K filed with

the SEC on March 2, 2009, and available on the Company's website at www.UNS.com. Since Mr. Pignatelli was retirement eligible, his accruals in 2006, 2007 and 2008 were fully expensed during the year of the award, rather than expensed over a three-year vesting period. These amounts disregard estimates of forfeitures related to service based vesting conditions.

(3) The 2008 PEP awards included in this column were paid during the first four months of 2009.

(4) This column reflects the change in the actuarial present value of the accumulated benefit under all defined benefit plans (the Retirement Plan and Excess Benefit Plan). Due to a change in actuarial assumptions for the 2007 measurement date, the change in pension value for four of the Named Executives was negative for 2007, and in accordance with the SEC rules, we report these amounts as zero. We do not pay "above market" interest on non-qualified deferred compensation; therefore, this column reflects pension accruals only. See the discussion of the non-qualified DCP on page 34.

(5) The amounts in the "All Other Compensation" column include the following payments that we made on behalf of the Named Executives:

Name	Year	Qualified Plan 401(k) Matching Contributions ($)	Non-Qualified Plan 401(k) Matching Contributions ($)	Club Memberships ($)	Spouse Travel ($)	Total ($)
James S. Pignatelli	2008	10,350	0	1,080	2,102	13,532
Kevin P. Larson	2008	10,350	3,840	0	176	14,366
Michael J. DeConcini	2008	10,350	4,055	1,080	0	15,485
Raymond S. Heyman	2008	10,350	4,047	0	11	14,408
Karen G. Kissinger	2008	10,350	832	0	0	11,182

The "Club Memberships" and "Spouse Travel" columns include the incremental cost to the Company of such benefits. Spouse travel costs, which may include airfare and meals for the Named Executives' spouses for the annual Board retreat, and other company-related travel.

Effective January 1, 2009, Mr. Bonavia became Chairman of the Board, President and Chief Executive Officer of UniSource Energy, TEP and UES. Since Mr. Bonavia was not with the Company in 2008, he is not included as a "Named Executive" in this proxy statement. Mr. Bonavia's initial annual base salary will be $600,000. Mr. Bonavia will participate in UniSource Energy's annual cash incentive compensation program with a target award for 2009 of 80% of base salary and a maximum award equal to 120% of base salary, and will participate in the 2006 Omnibus Plan as well. Mr. Bonavia will be entitled to severance pay of 200% of his base salary, plus pro rata incentive compensation, if his employment is terminated by UniSource Energy without cause or if he terminates his employment for good reason within three years of his employment. Mr Bonavia will be entitled to a severance payment of 200% of the sum of base salary and bonus, plus pro rata incentive compensation, if UniSource Energy terminates his employment without cause or if he terminates employment for good reason within 24 months of a change in control.

GRANTS OF PLAN-BASED AWARDS—2008

The following table sets forth information regarding plan-based awards to our Named Executives in 2008. The compensation plans under which the grants in the following table were made are generally described in the "Compensation Discussion and Analysis" section, beginning on page 12 and include the UniSource Energy PEP, which provides for non-equity (cash) performance awards, and the 2006 Omnibus Plan, which provides for equity-based performance awards including stock options and performance shares.

Name	Grant Date	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards (1)			Estimated Future Payouts Under Equity Incentive Plan Awards (2)			All Other Option Awards: Number of Securities Under-lying Options (#)(3)	Exercise or Base Price of Option Awards ($/Sh) (4)	Grant Date Fair Value of Stock and Option Awards ($)(5)
		Thresh-old ($)	Target ($)	Maxi-mum ($)	Thresh-old (#)	Target (#)	Maxi-mum (#)			
JAMES S. PIGNATELLI										
PEP	2/27/2008	290,400	580,800	871,200						
Performance Share	2/27/2008				6,680	13,360	20,040			349,765
Stock Options	2/27/2008							82,470	26.18	349,768
KEVIN P. LARSON										
PEP	2/27/2008	79,000	158,000	237,000						
Performance Share	2/27/2008				2,905	5,810	8,715			152,106
Stock Options	2/27/2008							35,890	26.18	152,215
MICHAEL J. DECONCINI										
PEP	2/27/2008	80,300	160,500	240,800						
Performance Share	2/27/2008				2,950	5,900	8,850			154,462
Stock Options	2/27/2008							36,460	26.18	154,633

Name	Grant Date	Estimated Possible Payments Under Non-Equity Incentive Plan Awards (1)			Estimated Possible Payments Under Equity Incentive Plan Awards (2)			All Other Option Awards: Number of Securities Under-lying Options (#)(3)	Exercise or Base Price of Option Awards ($/Sh) (4)	Grant Date Fair Value of Stock and Option Awards ($)(5)
		Thresh-old ($)(1)	Target ($)	Maxi-mum ($)	Thresh-old (#)	Target (#)	Maxi-mum (#)			
RAYMOND S. HEYMAN										
PEP	2/27/2008	79,000	158,000	237,000						
Performance Share	2/27/2008				2,905	5,810	8,715			152,106
Stock Options	2/27/2008							35,890	26.18	152,215
KAREN G. KISSINGER										
PEP	2/27/2008	49,800	99,600	149,400						
Performance Share	2/27/2008				2,290	4,580	6,870			119,904
Stock Options	2/27/2008							28,280	26.18	119,940

(1) The amounts shown in this column reflect the range of payouts (50%-150% of the target award) for 2008 performance under the Company's PEP, as described in the "Short-Term Incentive Compensation" section of the Compensation Discussion and Analysis above. These amounts are based on the individual's current salary and position. The amount of cash incentive actually paid under the PEP for 2008 is reflected in the Summary Compensation Table above.

(2) The amounts shown in this column reflect the range (50%-150% of the target award) of payouts in the form of performance shares targeted for 2008 performance under the 2006 Omnibus Plan for long-term incentive compensation, as described in the "Long-Term Incentive Compensation" section of the Compensation Discussion and Analysis above. The following example is an illustration of the Company's method for determining the threshold, target and maximum number of shares subject to the equity incentive awards under the long-term incentive plan. In 2008, the CEO's base salary was $726,000; therefore, the target value of the CEO's long-term incentive award was $726,000, which equaled 100% of his base salary. As described in the "Compensation Discussion and Analysis," we granted one-half of that award ($726,000/2 = $363,000) in the form of performance shares and one-half in the form of stock options. Each performance share had an initial value equal to the fair market value of one share of our common stock as of a date preceding the date of the Compensation Committee meeting at which the awards were granted ($27.17), which produced a target award of 13,360 performance shares ($363,000/$27.17= 13,360 shares). Threshold equaled 6,680 shares, which was 50% of target (13,360 * 50% = 6,680), and maximum equaled 20,040 shares, which was 150% of target (13,360 * 150% = 20,040).

(3) Stock options granted under the 2006 Omnibus Plan are described in the Outstanding Equity Awards at Fiscal Year-End Table below. Options are granted with an exercise price equal to 100% of the fair market value on the date of grant; they vest in one-third increments over a three year period and expire after 10 years. The number of stock options awarded was determined by dividing the target value of the stock option award ($363,000) by the FAS 123R

"fair value" of an option as of a date preceding the date of the Compensation Committee meeting at which the options were granted ($4.40154), resulting in a grant of 82,470 stock options ($363,000/$4.40154 = 82,471, which was rounded down to 82,470). The exercise price for each option was set at the closing price on the actual grant date.

(4) Exercise price for the February 27, 2008 stock option award was $26.18, which was the closing price of the Company's common stock on the NYSE on the grant date.

(5) This amount has been determined in accordance with FAS 123R based on the fair value of our common stock as of the grant date, which was $26.18 per share for 2008 awards.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END – 2008

The following table summarizes the number of securities underlying outstanding plan awards for each Named Executive as of December 31, 2008:

	Option Awards(1)					Stock Awards(2)	
Name	Grant Date	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Options (#) Unexer-cisable	Option Exercise Price ($)	Option Expiration Date	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(3)
James S. Pignatelli							
	7/16/1999	114,500		12.28	7/16/2009		
	8/3/2000	175,000		15.28	8/3/2010		
	8/2/2001	150,000		17.91	8/2/2011		
	1/2/2002	150,000		18.12	1/2/2012		
	5/9/2003	21,226		17.84	5/9/2013		
	5/5/2006	30,673	15,337	30.55	5/5/2016		
	3/20/2007	13,100	26,200	37.88	3/20/2017		
	2/27/2008		82,470	26.18	2/27/2018		
	5/5/2006					3,655	107,311
	3/20/2007					6,340	186,142
	2/27/2008					6,680	196,125

	Option Awards(1)					Stock Awards(2)	
Name	Grant Date	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Options (#) Unexer-cisable	Option Exercise Price ($)	Option Expiration Date	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(3)
Kevin P. Larson							
	8/3/2000	17,000		15.28	8/3/2010		
	1/2/2002	35,000		18.12	1/2/2012		
	5/9/2003	7,783		17.84	5/9/2013		
	5/5/2006	13,273	6,637	30.55	5/5/2016		
	3/20/2007	5,653	11,307	37.88	3/20/2017		
	2/27/2008		35,890	26.18	2/27/2018		
	5/5/2006					1,582	46,448
	3/20/2007					4,100	120,376
	2/27/2008					8,715	255,872
Michael J. DeConcini							
	7/16/1999	8,900		12.28	7/16/2009		
	8/3/2000	40,000		15.28	8/3/2010		
	8/2/2001	30,000		17.91	8/2/2011		
	1/2/2002	40,000		18.12	1/2/2012		
	5/9/2003	8,137		17.84	5/9/2013		
	5/5/2006	13,273	6,637	30.55	5/5/2016		
	3/20/2007	5,653	11,307	37.88	3/20/2017		
	2/27/2008		36,460	26.18	02/27/2018		
	5/5/2006					1,582	46,448
	3/20/2007					4,100	120,376
	2/27/2008					8,850	259,836

	Option Awards(1)					Stock Awards(2)	
Name	Grant Date	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Options (#) Unexer-cisable	Option Exercise Price ($)	Option Expiration Date	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(3)
Raymond S. Heyman							
	9/15/2005	50,000		33.55	9/15/2015		
	5/5/2006	13,273	6,637	30.55	5/5/2016		
	3/20/2007	5,653	11,307	37.88	3/20/2017		
	2/27/2008		35,890	26.18	2/27/2018		
	5/5/2006					1,582	46,448
	3/20/2007					4,100	120,376
	2/27/2008					8,715	255,872
Karen G. Kissinger							
	8/2/2001	7,000		17.91	8/2/2011		
	1/2/2002	1,152		18.12	1/2/2012		
	5/5/2006	10,526	5,264	30.55	5/5/2016		
	3/20/2007	4,466	8,934	37.88	3/20/2017		
	2/27/2008		28,280	26.18	2/27/2018		
	5/5/2006					1,254	36,817
	3/20/2007					3,240	95,126
	2/27/2008					6,870	201,703

(1) All options listed above vest at a rate of 33 1/3% per year over the first three years of the 10-year option term. The option expiration date for Mr. Pignatelli is accurate as of December 31, 2008; however, Mr. Pignatelli retired effective as of January 1, 2009 and, as a result, his options expire three years from the date of retirement or expiration date, if sooner.

(2) Performance shares vest after three years based on performance of the cumulative goals over the applicable three-year period.

(3) The amounts shown reflect the projected value of the performance share awards as of December 31, 2008. The projections regarding achievement of the performance goals were the same projections used to determine the 2008 compensation expense related to the outstanding awards for financial reporting purposes, and were done in the manner required by Financial Accounting Standards 123(R).

OPTION EXERCISES AND STOCK VESTED

The following table includes certain information with respect to the options exercised by our Named Executives during the year ended December 31, 2008:

	Option Awards	
Name	**Number of Shares Acquired on Exercise (#)(1)**	**Value Realized on Exercise ($)(2)**
James S. Pignatelli	45,096	832,510
Michael J. DeConcini	4,000	69,990

(1) Of shares exercised, the following numbers of shares were due to options that otherwise would have expired during the year: James S. Pignatelli, 45,096. Michael J. DeConcini, 4,000. Mr. DeConcini retained 4,000 of the shares acquired through the exercise of the options indicated above.

(2) For options that are exercised in cashless transactions, we base this value on the spread between the exercise price and the actual price at which the shares of common stock are sold in the market. For options that are exercised and retained by the Named Executive, we base this value on the spread between the exercise price and the actual market price of our common stock at the time of exercise.

PENSION BENEFITS

The following table shows the present value of accumulated benefits payable to each of the Named Executives, including the number of years of service credited to each such Named Executive, under each of the Retirement Plan and the Excess Benefit Plan determined using interest rate and mortality rate assumptions used in the Company's financial statements as set forth on pages 142-149 of the Company's annual report on Form 10-K. Information regarding the Retirement Plan and the Excess Benefit Plan can be found under the heading "Retirement and Other Benefits" on page 23.

Name	Plan Name	Number of Years Credited Service (#)	Present Value of Accumulated Benefit ($)	Payments During Last Fiscal Year ($)
James S. Pignatelli	Tucson Electric Power Salaried Employees Retirement Plan (1)	14.33	556,545	0
	Tucson Electric Power Excess Benefit Plan (2)	14.33	4,547,191	0
Kevin P. Larson	Tucson Electric Power Salaried Employees Retirement Plan (1)	23.83	428,588	0
	Tucson Electric Power Excess Benefit Plan (2)	23.83	403,186	0
Michael J. DeConcini	Tucson Electric Power Salaried Employees Retirement Plan (1)	20.08	236,899	0
	Tucson Electric Power Excess Benefit Plan (2)	20.08	321,025	0
Raymond S. Heyman	Tucson Electric Power Salaried Employees Retirement Plan (1)	3.33	65,112	0
	Tucson Electric Power Excess Benefit Plan (2)	3.33	216,225	0
Karen G. Kissinger	Tucson Electric Power Salaried Employees Retirement Plan (1)	18	388,618	0
	Tucson Electric Power Excess Benefit Plan (2)	18	394,263	0

(1) The Retirement Plan is intended to meet the requirements of a qualified benefit plan for Code purposes, and is funded by the Company and made available to all eligible employees. The Retirement Plan provides an annual income upon retirement based on the following formula:

1.6% x years of service (up to 25 years) x final average pay

Final average pay is calculated as the average of basic monthly earnings on the first of the month following the employee's birthday during the five consecutive plan years in which basic monthly earnings were the highest, within the last 15 plan years before retirement. Years of service are based on years and months of employment. A Retirement Plan participant is fully vested in his or her retirement benefit after five years of service. The maximum benefit available under the Retirement Plan is an annual income of 40% of final average pay (as defined above). Plan compensation for purposes of determining final average pay is limited by IRS compensation limits under Code Section 401(a)(17). For 2008, the limit was $230,000 in annual income. Employees are eligible to retire early with an unreduced pension benefit if (i) the combination of their age and years of service equals or exceeds 85 or (ii) they are age 62 and have completed 10 years of service. Employees are also eligible to early retirement with a reduced pension benefit at age 55 with at least 10 years of service. The reduction at age 55 with 10 years of service is 42.6% and continues to be reduced at a lesser amount up to age 62, where there is no reduction. All optional forms of the benefit are actuarially equivalent.

(2) The Retirement Plan is subject to Code limitations on the amount of compensation that can be taken into account and on the amount of benefits that can be provided. The Excess Benefit Plan provides the retirement benefits to officers that would have been provided under the Retirement Plan if the Code limitations did not apply. The Excess Benefit Plan retirement benefit is calculated generally using the same pension formula as the Retirement Plan formula but with some modifications. Compensation for purposes of the Excess Benefit Plan is determined without regard to IRS limits on compensation and by including voluntary salary reductions to the DCP, and any annual incentive payment received under the PEP. The retirement benefit payable from the Excess Benefit Plan is reduced by the benefit payable to that person from the Retirement Plan. Full vesting occurs after five years of service. Benefits are payable in a lump sum or annuity, at the retiree's election.

NON-QUALIFIED DEFERRED COMPENSATION

UniSource Energy sponsors the DCP for directors, officers and certain other employees of UniSource Energy. Under the DCP, employee participants are allowed to defer on a pre-tax basis up to 100% of base salary and cash bonuses and non-employee director participants are allowed to defer up to 100% of their cash compensation. This deferral plan also allows the executive employee participants to receive the 401(k) Company match that cannot be contributed to the 401(k) Plan because of limitations imposed by the Code. The deferred amounts are valued daily as if invested in one or more of a number of investment funds, including UniSource Energy stock units, each of which may appreciate or depreciate in value over time. The choice of investment funds is determined by the individual participant.

Name	Executive Contributions in Last Fiscal Year ($)(1)	Registrant Contributions in Last Fiscal Year ($)(4)	Aggregate Earnings in Last Fiscal Year ($)(2)	Aggregate Withdrawals/ Distributions ($)	Aggregate Balance at Last Fiscal Year End ($)(3)
James S. Pignatelli	0	5,375	(266,998)	0	1,350,336
Kevin P. Larson	0	3,357	(1,210)	0	34,934
Michael J. DeConcini	0	3,357	(804)	0	24,373
Raymond S. Heyman	0	3,558	6	0	6,203
Karen G. Kissinger	0	527	(2,957)	0	59,953

(1) Represents contributions to the DCP by the Named Executives during the year. These amounts are included in the salary column of the "Summary Compensation Table" above.

(2) Represents the total market based earnings (losses) for the year on all deferred compensation under the plan based on the investment returns associated with the investment choices made by the Named Executive. Amounts in this column are not included in the "Summary Compensation Table."

(3) The amount reported for Mr. Pignatelli includes a total of $250,475 of executive contributions and registrant contributions that were reported in the Summary Compensation Table in 2006 and 2007.

(4) The amounts shown in this column reflect the actual contributions made in 2008 for the 2007 plan year.

The following table shows the deemed investment options available, and the annual rate of return for the calendar year ended December 31, 2008, under the DCP.

Name of Fund	Rate of Return	Name of Fund	Rate of Return
Fidelity Retirement Money Market	2.93%	Fidelity Spartan Us Equity Index	(37.03%)
Fidelity Intermediate Bond	(5.84%)	Fidelity Growth Company	(40.90%)
Janus Flexible Bond	5.64%	Fidelity Low Price Stock	(36.17%)
Fidelity Asset Manager	(27.80%)	Janus Worldwide	(45.02%)
Fidelity Equity-Income	(41.64%)	UniSource Energy Corporation Stock	3.67%)
Fidelity Magellan	(49.40%)		

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

Each of the Named Executives, other than Mr. Pignatelli and Mr. Heyman, are subject to a Change in Control Agreement. For the purpose of the Agreements, a "Change in Control", as defined in the Agreements, includes the acquisition of beneficial ownership of 30% of the common stock of UniSource Energy, certain changes in the Board, approval by the shareholders of certain mergers or consolidations or certain transfers of the assets of UniSource Energy. The Agreements provide that each officer shall be employed by TEP or one of its subsidiaries or affiliates, in a position comparable to his current position, with compensation and benefits, which are at least equal to his then current compensation and benefits, for an employment period of five years after a Change in Control (subject to earlier termination due to the officer's acceptance of a position with another company or termination for cause). For purposes of this section, titled "Potential Payments Upon Termination or Change in Control", only, "TEP" shall mean TEP or one of its subsidiaries or affiliates, as applicable.

The Agreements are in effect until the later of: (i) five years after the date either TEP or the officer gives written notice of termination of the Agreement, or (ii) if a Change in Control occurs during the term of the Agreements, five years after the Change in Control. On March 29, 2004, a Change in Control occurred for purposes of the Agreements when our shareholders, at a special meeting, approved the acquisition agreement that provided for an affiliate of Saguaro Utility Group L.P. to acquire all of our outstanding shares of common stock.

On March 3, 2005, TEP provided the officers of the Company with written notice of termination of the Agreements effective March 3, 2010, the fifth anniversary of the date of the written notice of termination. In December 2006, the CEO of the Company waived all rights he otherwise would have had for the remaining effective period under his Agreement and terminated the Agreement to which he and TEP had been party.

During the remaining term of the Agreements currently in effect, in the event that an officer's employment is terminated by TEP (with the exception of termination due to the officer's acceptance of another position or for cause), or if the officer terminates employment because i) there was a material change by TEP of the officer's status, title, authority, duties or responsibilities, ii) the officer was assigned or reassigned to another place of employment more than fifty miles from the officer's current place of employment, iii) a liquidation, dissolution, consolidation or merger of TEP occurred, or iv) a reduction in the officer's target compensation occurred, prior to March 29, 2009 (or within five years of any subsequent Change in Control), the officer is entitled to severance benefits in the form of: (a) a lump sum payment equal to the present value of three times the sum of annual salary and prorated target bonus ("cash severance"), (b) the present value of the additional amount (including any amount under the Excess Benefit Plan) the officer would have received under the Retirement Plan if the officer had continued to be employed for the five-year period after a Change in Control occurs, plus (c) the present value of any officer award under the 2006 Omnibus Plan or any successor plan, which is outstanding at the time of the officer's termination (whether vested or not), prorated based on length of service. Such officer is also entitled to continue to participate in TEP's health, death and disability benefit plans for five years after the termination. The Agreements further provide that TEP will make a payment to the officer to offset any golden parachute excise taxes that may be imposed in accordance with Code sections 280G and 4999. Any payments made in respect of such excise taxes are not deductible by us. Cash severance would also be paid under the Agreements if an officer dies or becomes disabled prior to March 29, 2009 (or within five years of any subsequent Change in Control).

Beginning in 2006, all long-term incentive awards contain a "double trigger" vesting provision, which provides for accelerated vesting only if outstanding awards are not assumed by an acquirer or the Named Executive is terminated without cause within 24 months of a Change in Control. The double trigger, which is viewed as a corporate governance "best practice", ensures that the Named Executives do not receive accelerated benefits unless they are adversely affected by the Change in Control.

Other than the Agreements described above, we have not entered into any other severance agreements or employment agreements with any Named Executives.

The following table and summary set forth potential payments payable to our Named Executives upon termination of employment or a Change in Control. The table below reflects amounts payable to our Named Executives assuming their employment was terminated on December 31, 2008:

Name	If Retirement or Voluntary Termination Occurs (1)	If "Change In Control" Termination Occurs ($) (2)	If Death or Disability Occurs ($) (3)
James S. Pignatelli	--	0	262,255
Kevin P. Larson	--	3,426,554	114,130
Michael J. DeConcini	--	3,169,832	115,943
Raymond S. Heyman	--	0	114,130
Karen G. Kissinger	--	2,591,663	89,930

(1) In the event of retirement or voluntary termination, each of the Named Executives would be entitled to receive vested and accrued benefits payable from the Retirement Plan and the Excess Benefit Plan, but no form or amount of any such payment would be increased or otherwise enhanced nor would vesting be accelerated with respect to such plans. In addition, no accelerated vesting of options or performance shares would occur. Retirement Plan and Excess Benefit Plan information for the Named Executives is set forth in the "Pension Benefits Table" above. Mr. Heyman is not vested in the retirement plans as of December 31, 2008.

(2) In December 2006, James S. Pignatelli waived all rights under his Agreement and terminated the Agreement to which he and TEP had been party. Mr. Heyman does not have an Agreement. The breakout of the above referenced elements for the three Named Executives is as follows:

Named Executive	Cash ($)	Prorated Bonus ($)	Stock Options ($)	Performance Shares ($)	Medical Benefits ($)	Retirement Benefits ($)	Tax Gross-up ($)	Total ($)
Kevin P. Larson	1,422,000	158,000	114,130	290,958	73,906	462,888	904,673	3,426,554
Michael J. DeConcini	1,444,500	160,500	115,943	293,600	82,756	213,264	859,269	3,169,832
Karen Kissinger	1,045,800	99,600	89,930	229,595	82,567	402,732	641,438	2,591,663

(3) Amounts in this column reflect the value of all unvested options that would accelerate upon the death or disability of the Named Executives. There is no acceleration of performance shares. In addition, in the event of death, the Named Executive's survivor would be entitled to receive a death benefit in the form of a lump sum or survivor annuity which is funded from the Retirement Plan and Excess Benefit Plan. The amount payable to the survivor would be less than the amount that would otherwise have been payable to the Named Executive had the Named Executive survived and received retirement benefits under the Retirement Plan and Excess Benefit Plan. There would be no enhancements as to form, amount or vesting of such benefits in the event of a Named Executive's death.

DIRECTOR COMPENSATION

For 2008, our non-employee directors received the following compensation:

1. Annual cash retainer of $40,000, paid in monthly installments.
2. Additional annual cash retainer of $20,000 for the Lead Director, $10,000 for the Audit Chair, $7,500 for each of the Compensation and Corporate Governance Chairs, and $5,000 for all other committee chairs, all of which are paid in quarterly installments.
3. Board and committee meeting fees of $1,000 per meeting.
4. Annual award of $45,000 in restricted stock units:
   - Directors serving on the date of the Annual Shareholders' meeting receive a grant on the date of that meeting. Any person who first becomes a director after the Annual Shareholders' meeting receives a grant on a date approved by the Compensation Committee. All restricted stock unit grants to directors vest at the earlier of the next annual meeting following grant date or the first anniversary of grant.
   - The actual number of restricted stock units granted is calculated by dividing $45,000 by the closing price of our common stock on the date of grant.
   - Vested stock units must be deferred and distributed in January of the year following the year during which a director ceases to serve as a member of our Board. Deferred stock units accrue dividend equivalents during the deferral period. Deferred stock units will be distributed in shares of Company stock.

Mr. Pignatelli, our CEO during 2008, did not receive any additional compensation for serving as a director. Directors may elect to defer cash fees and retainers under the DCP, which is described on page 23.

In 2007, we adopted formal stock ownership guidelines for our non-employee directors. Non-employee directors are expected to accumulate Company shares with a value equal to 500% of the annual equity grant. Shares owned outright, including shares held in street name accounts, jointly with spouse, or in trust for the non-employee director's benefit, and deferred stock units count towards meeting the guideline.

The following table summarizes the compensation earned by non-employee directors of the Company for the year ended December 31, 2008.

Name (1)	Fees Earned or Paid in Cash ($)(2)	Stock Awards ($) (3)(4)(5)	All Other Compensation ($)(6)	Total ($)
Lawrence J. Aldrich	**73,000**	**46,875**	**5,014**	**124,889**
Barbara M. Baumann	**83,000**	**46,875**	**3,982**	**133,857**
Larry W. Bickle	**73,333**	**46,875**	**10,621**	**130,829**
Elizabeth T. Bilby	**72,000**	**46,875**	**7,009**	**125,884**
Harold W. Burlingame(8)	**97,500**	**46,875**	**10,339**	**154,714**
John L. Carter(8)	**120,000**	**46,875**	**4,826**	**171,701**
Robert A. Elliott(8)	**97,500**	**46,875**	**3,637**	**148,012**
Daniel W. L. Fessler(8)	**87,000**	**125,250**	**5,894**	**218,144**
Louise L. Francesconi(7)	**31,666**	**16,875**	**611**	**49,152**
Kenneth Handy	**75,000**	**46,875**	**5,429**	**127,304**
Warren Y. Jobe(8)	**94,000**	**46,875**	**9,303**	**150,178**
Ramiro G. Peru	**73,000**	**69,375**	**591**	**142,966**
Gregory A. Pivirotto	**71,000**	**69,375**	**316**	**140,691**
Joaquin Ruiz	**73,666**	**46,875**	**3,424**	**123,965**

(1) Mr. Pignatelli is not included in this table, as he is an employee of the Company and thus receives no compensation for his service as a director. The compensation received by Mr. Pignatelli as an employee of the Company is shown in the "Summary Compensation Table."

(2) Lawrence J. Aldrich, Barbara M. Baumann, Harold W. Burlingame, Kenneth Handy and Joaquin Ruiz, deferred 100% of fees earned in 2008 into the DCP.

(3) Each non-employee director received an annual restricted stock unit award valued at $45,000 in 2008. Values reflected in the table are consistent with FAS 123R grant date fair value and include amortization of a portion of a May 2007, June 2007, February 2008, May 2008 and August 2008 awards. This amount disregards estimates of forfeitures related to service based vesting conditions. Each of the directors in office on May 2, 2008 was awarded 1,419.1 restricted stock units at a fair market value share price of $31.71. On February 11, 2008, Mr. Peru and Mr. Pivirotto were each awarded 1,565.2 restricted stock units at a fair market value share price of $28.75. On August 14, 2008, Mrs. Francesconi was awarded 1,399.7 restricted stock units at a fair market value of $32.15. After a one year vesting period the restricted stock units convert to deferred stock units and are payable in January that follows the calendar year in which the director ceases to be a Board member. The award price for the annual director equity award was the closing price on the date of grant.

The values reflected in this column for Mr. Fessler also reflect the 2008 expense attributable to the restricted stock units granted in May of 2007. In May 2007, the Compensation Committee approved a grant of 4,902.5 restricted stock units to Mr. Fessler. Mr. Fessler served as a director on the Board from 1998 to 2003. In 2005, Mr. Fessler rejoined the Board as a director. Upon Mr. Fessler's initial retirement from the Board in 2003, Mr. Fessler had 7,201 vested stock options outstanding under the 1994 Outside Directors Stock Option Plan. At the time of his retirement, UniSource Energy mistakenly informed Mr. Fessler that the options would expire at the end of their original terms. However, under the terms of the plan, the options expired six months after his retirement. In reliance on the mistaken information, Mr. Fessler failed to exercise the options prior to their expiration. The grant in May 2007 was in an amount intended to restore Mr. Fessler to the position he would have been in had he exercised the options at the end of the six month period after his retirement and held the stock received upon such exercise through the date of the May 2007 award.

(4) As of December 31, 2008 the unvested stock units held by directors were as follows: Mr. Aldrich held 1,419 stock units; Mrs. Baumann held 1,419 stock units; Mr. Bickle held 1,419 stock units; Mrs. Bilby held 1,419 stock units; Mr. Burlingame held 1,419 stock units; Mr. Carter held 1,419 stock units; Mr. Elliott held 1,419 stock units; Mr. Fessler held 1,419 stock units; Mr. Handy held 1,419 stock units; Mr. Jobe held 1,419 stock units; Mr. Ruiz held 1,419 stock units; Mr. Pivirotto held 1,419 stock units; Mr. Peru held 1,419 stock units; and Ms. Francesconi held 1,400 stock units.

(5) As of December 31, 2008 all stock options are vested and are reported in the Security Ownership of Management table on pages 6-7.

(6) Amounts represent the value of dividend equivalents associated with restricted stock units and stock option awards held by the directors, expensed in accordance with FAS 123R. The amounts also include reimbursement to the applicable directors for travel expenses incurred by their respective spouses in attending the annual meeting dinner, the board retreat and/or the holiday dinner and a tax gross-up with respect to the reimbursement.

(7) Ms. Francesconi was appointed to the Board, effective August 14, 2008, which is reflected in her compensation for 2008.

(8) The directors noted were members of the Corporate Development Committee during 2008, which is discussed under the "Board Committees" section below. These directors received compensation for attending meetings of the Corporate Development Committee consistent with the compensation parameters set forth under "Director Compensation" on page 37. The compensation for each of the noted directors is greater than the compensation shown for the other directors due to the number of meetings held by the Corporate Development Committee in 2008.

EQUITY COMPENSATION PLAN INFORMATION

Equity Compensation Plans

Our only equity-based compensation plan that has not been approved by shareholders is the DCP. Shareholder approval of the DCP has not been required because the provisions of the DCP permit the Company to payout deferred shares accumulated under the DCP in the form of cash or stock. Under the terms of the plan, distribution of deferred shares will be made in cash, unless the participant elects to receive the deferred shares in Company stock. Under the DCP, certain eligible officers and other employees selected for participation, and non-employee members of the Board, may elect to defer a percentage of the compensation or fees that would otherwise become payable to the individual for his services to us. We also credit DCP accounts of employees participating in our 401(k) Plan with the additional amount of UniSource Energy matching contributions that the participant would have been entitled to under the 401(k) Plan if certain Code limits did not apply to limit the amount of UniSource Energy matching contributions made under the 401(k) Plan. Each participant in the DCP may elect that his deferrals be credited in the form of deferred shares instead of cash. Deferred shares accrue dividend equivalents, credited in the form of additional deferred shares, as dividends are paid by UniSource Energy on its issued and outstanding common stock. Each participant elects the time and manner of payment (lump sum or installments) of his deferred shares under the DCP.

Equity Compensation

The following table sets forth information as of December 31, 2008, with respect to UniSource Energy's equity compensation plans.

Plan Category	Number of Shares of UniSource Energy Common Stock to be Issued Upon Exercise of Outstanding Options and Rights	Weighted-Average Exercise Price of Outstanding Options	Number of Shares of UniSource Energy Common Stock Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Shares Reflected in the First Column)
Equity Compensation Plans Approved by Shareholders (1)	2,012,120 (2)	$22.49583 (3)	1,392,860 (1)
Equity Compensation Plans Not Approved by Shareholders	84,190 (4)	--	-- (5)
Total	2,096,310	--	--

(1) The equity compensation plans that have been approved by shareholders are the UniSource Energy Corporation 1994 Omnibus Stock and Incentive Plan ("1994 Stock and Incentive Plan"), the UniSource Energy Corporation 1994 Outside Director Stock Option Plan (the "1994 Directors Plan") and the 2006 Omnibus Plan. Awards were made under the 1994 Stock and Incentive Plan and the 1994 Directors Plan until February 2004 at which time no further awards could be made under those plans. In May 2006, the 2006 Omnibus Plan was approved by shareholders and includes awards in the form of options, restricted stock, stock units and dividend equivalents. While the 1994 plans expired in February 2004 and no further awards could be made under those plans after that date, the 1994 plans remain in effect with respect to previous awards until all awards have expired or terminated or shall have been exercised or fully vested, and any stock thereto shall have been purchased or acquired. No shares that were available to be issued under the 1994 Directors Plan at the time of its termination are available for awards under the 2006 Omnibus Plan with respect to awards that are forfeited, terminated, canceled or expired.

(2) Includes options outstanding as to 1,634,627 shares, stock units, dividend equivalent stock units and restricted stock units (payable in an equivalent number of shares) outstanding as to 377,493 shares.

(3) Calculated based on the outstanding options and exclusive of outstanding stock units.

(4) Deferred shares credited under the DCP.

(5) There is no explicit share limit under the DCP. The number of shares to be delivered with respect to the DCP in the future depends on the levels of fees and compensation that participants elect to defer under the DCP. Any UniSource Energy shares used to satisfy our common stock obligations under the DCP will be shares that have been purchased on the open market.

CORPORATE GOVERNANCE

Board Meetings

In 2008, the Board held a total of eight regular and special meetings. Each director attended at least 95% of the aggregate total number of Board meetings and meetings of committees of which they are a member. Additionally, the non-management Directors met at regularly scheduled executive sessions without management present. Mr. Carter, a non-management director, presided over and was the Lead Director at these executive sessions.

The Company does not have a formal policy with respect to attendance of Board members at annual meetings of shareholders, but encourages such attendance. All of the Board members holding office at the time attended the 2008 Annual Meeting.

Board Communication

Shareholders or other interested parties wishing to communicate with the Board, the non-management directors or any individual director may contact the Lead Director by mail, addressed to UniSource Energy Lead Director, c/o Corporate Secretary, UniSource Energy Corporation, One South Church Avenue, Suite 1820, Tucson, Arizona 85701. The communications will be kept confidential and forwarded to the Lead Director. Communications received by the Lead Director will be forwarded to the appropriate director(s) or to an individual non-management director.

Shareholders or other interested parties wishing to communicate with the Board regarding non-financial matters may contact the Chairperson of the Corporate Governance and Nominating Committee either by mail, addressed to Chairperson, Corporate Governance and Nominating Committee, UniSource Energy Corporation, P.O. Box 31771, Tucson, Arizona 85751-1771, or by e-mail at unscorpgov@earthlink.net. Shareholders or other interested parties wishing to communicate with the Board regarding financial matters may contact the Chairperson of the Audit Committee either by mail, addressed to Chairperson, Audit Committee, UniSource Energy Corporation, P.O. Box 46093, Denver, Colorado 80201, or by e-mail at unscorpaudit@earthlink.net.

Items that are unrelated to a director's duties and responsibilities as a Board member may be excluded from consideration, including, without limitation, solicitations and advertisements, junk mail, product-related communications, job referral materials such as resumes, surveys and material that is determined to be illegal or otherwise inappropriate.

DIRECTOR INDEPENDENCE CRITERIA

The Board has adopted Director Independence Standards to comply with NYSE rules for determining independence, among other things, in order to determine eligibility to serve on the Audit Committee, the Compensation Committee and the Corporate Governance and Nominating Committee. The Director Independence Standards, amended as of February 9, 2007, are available on our website at www.UNS.com and are available in print to any shareholder who requests it.

No director may be deemed independent unless the Board affirmatively determines, after due deliberation, that the director has no material relationship with the Company either directly or as a partner, shareholder or officer of an organization that has a relationship with the Company. In each case, the Board broadly considers all the relevant facts and circumstances from the standpoint of the director as well as from that of persons or organizations with which the director has an affiliation and applies these standards.

Annually, the Board determines whether each director meets the criteria of independence. Based upon the foregoing criteria, the Board has deemed each director to be independent, with the exception of Mr. Pignatelli (who retired effective as of January 1, 2009), Ms. Bilby and Mr. Bonavia (who became the new Chief Executive Officer effective January 1, 2009). For each other director who is deemed independent, there were no other significant transactions, relationships or arrangements that were considered by the Board in determining that the director is independent. See "Transactions with Related Persons" on page 45.

Board Committees

Corporate Governance and Nominating Committee

The Corporate Governance and Nominating Committees operates under the provisions of a committee charter. The Corporate Governance and Nominating Committee reviews and recommends corporate governance principles, interviews potential directors and nominates and recommends to the shareholders and directors, as the case may be, qualified persons to serve as directors. The Corporate Governance and Nominating Committee also reviews and recommends membership for all the committees to the Board and reviews applicable rules and regulations relating to the duties and responsibilities of the Board. Our Corporate Governance and Nominating Committee held three meetings in 2008 and was in compliance with its written charter.

The Corporate Governance and Nominating Committee identifies and considers candidates supplied by shareholders and Board members. The Corporate Secretary, as directed by the Corporate Governance and Nominating Committee, prepares portfolios for candidates that include confirmation of the candidate's interest, independence, biographical information, review of business background and experience and reference checks. The Corporate Governance and Nominating Committee then evaluates candidates using, in large part, the criteria set forth in the next paragraph and any other criteria the Corporate Governance and Nominating Committee deems appropriate, and conducts a personal interview with each candidate. Upon completion of this process, formal invitations are extended to accept election to the Board.

The Corporate Governance and Nominating Committee has not adopted specific minimum qualifications with respect to a committee-recommended Board nominee, but desirable qualifications are set forth in the Corporate Governance Guidelines and include prior community, professional or business experience that demonstrates leadership capabilities, the ability to review and analyze complex business issues, the ability to effectively represent the interests of our shareholders while keeping in perspective the interests of our customers, the ability to devote the time and interest required to attend and fully prepare for all regular and special Board meetings, the ability to communicate and work effectively with the other Board members and personnel and the ability to fully adhere to any applicable laws, rules or regulations relating to the performance of a director's duties and responsibilities.

While no formal policy exists, the Corporate Governance and Nominating Committee does consider recommendations for Board nominees received from our shareholders. The deadline for consideration of recommendations for next year's annual meeting of the shareholders is November 21, 2009. Recommendations must be in writing and include detailed biographical material indicating the candidate's qualifications and a written statement from the candidate of his willingness and availability to serve. Recommendations should be directed to the Corporate Secretary, UniSource Energy Corporation, One South Church Avenue, Suite 1820, Tucson, Arizona 85701. The Board will consider nominees on a case-by-case basis and does not believe a formal policy is warranted at this time due to a manageable volume of nominations.

Each member of our Audit Committee, Compensation Committee and Corporate Governance and Nominating Committee is independent based upon independence criteria established by our Board, which criteria are in compliance with applicable NYSE listing standards.

Compensation Committee

The Compensation Committee operates under the provisions of a committee charter, which was amended most recently in November 2007. The Compensation Committee Charter can be revised by action taken by the Compensation Committee. Under the terms of its charter, the Compensation Committee is required to consist of not fewer than three members of the Board who meet the independence requirements of the NYSE. In 2008, the Compensation Committee had six members who met those independence requirements.

In 2008, the Compensation Committee held five formal meetings, most of which were followed by an executive session in which management did not participate. The Compensation Committee Chair sets the agenda for each meeting, and in advance of each meeting reviews the agenda with management. The annual schedule of meetings is approved by the Board during the fourth quarter for the following year. In connection with Compensation Committee meetings, each Compensation Committee member receives a briefing book prior to each meeting that details each topic to be considered. The Compensation Committee Chair reports to the Board on Compensation Committee decisions and key actions following each meeting. The Compensation Committee members also complete a written assessment of the Compensation Committee's performance, with the last such assessment completed in September 2008.

The Board has delegated authority to the Compensation Committee to set CEO compensation levels, and to review and approve compensation for all of the Company's executives, including any equity compensation awarded under the 2006 Omnibus Plan. Under the terms of its charter, the Compensation Committee may delegate certain actions to management of the Company in connection with executive compensation. Day-to-day administration of director and executive compensation matters has been delegated to certain Company management personnel, with oversight provided by the Compensation Committee.

Compensation Consultant

The Compensation Committee has retained the services of Frederic W. Cook and Co., Inc. ("Cook"), a nationally recognized compensation consulting firm that serves as an independent advisor in matters related to executive compensation and non-employee director compensation. Representatives from Cook are available to Compensation Committee members on an ongoing basis and attend Compensation Committee meetings, as requested, either in person or telephonically. The Compensation Committee has sole discretion over the terms and conditions of the retention of consultants it retains. Cook maintains no other economic relations with the Company and does not provide any services to the Company other than those provided directly to the Compensation Committee.

The Compensation Committee Chair customarily provides assignments to Cook. In its role as executive compensation consultant to the Compensation Committee, Cook assists with peer group selection, the benchmarking of individual compensation levels, and the design of incentive plans and other compensation arrangements in which Company management participates. In furnishing this assistance, Cook provides competitive data and technical considerations, and recommends changes to the pay program and pay levels for consideration by the Compensation Committee.

Role of Executives in Establishing Compensation

Certain executives, including the CEO, the CFO and the General Counsel to the Company, routinely attend regular sessions of Compensation Committee meetings. The CEO makes recommendations to the Compensation Committee with respect to changes in compensation for senior executive positions (other than the CEO) and payouts under the annual incentive plan. The CEO also makes suggestions to the Compensation Committee regarding the design of incentive plans and other programs in which senior management participates.

The CFO provides information regarding short-term and long-term compensation targets, as well as updates on the progress of short- and long-term objectives. Additional Company personnel with expertise in and responsibility for compensation and benefits provide information regarding executive and director compensation, including cash compensation, equity awards, pensions, deferred compensation and other related information.

Audit Committee

The Audit Committee operates under the provisions of a committee charter. The Audit Committee reviews current and projected financial results of operations, selects a firm of independent registered public accountants to audit our financial statements annually, reviews and discusses the scope of such audit, receives and reviews the audit reports and recommendations, transmits its recommendations to the Board, reviews our accounting and internal control procedures with our internal audit department from time to time, makes recommendations to the Board for any changes deemed necessary in such procedures and performs such other functions as delegated by the Board. Our Audit Committee held six meetings in 2008 and was in compliance with its written charter, as amended in December 2007.

Upon the recommendation of the Audit Committee, our Board adopted a Code of Ethics for our directors, officers and employees.

Finance Committee

The Finance Committee reviews and recommends to the Board long-range financial policies, objectives and actions required to achieve those objectives. Specifically, the Finance Committee reviews capital and operating budgets, current and projected financial results of operations, short-term and long-range financing plans, dividend policy, risk management activities and major commercial banking, investment banking, financial consulting and other financial relations of UniSource Energy. Our Finance Committee held six meetings in 2008 and was in compliance with its written charter.

Environmental, Safety and Security ("ESS") Committee

The ESS Committee reviews the Company's structure and operations to assess whether significant operating risks in the areas of environmental, safety and security have been identified and appropriate mitigation plans have been implemented. The ESS Committee also reviews the processes in place which are designed to ensure compliance with all environmental, safety and security related legal and regulatory requirements, as well as reviews with management the impact of proposed or enacted laws or regulations related to environmental, safety and security issues. Our ESS Committee held three meetings in 2008 and was in compliance with its written charter.

Corporate Development Committee

The Corporate Development Committee was created in 2008 for the purpose of working on executive development and selecting a successor Chief Executive Officer for the Company. The Corporate Development Committee held 15 meetings in 2008. The Corporate Development Committee did not operate under the provisions of a charter and terminated at the end of 2008 following the hiring of the new Chief Executive Officer for the Company.

Compensation Committee Interlocks and Insider Participation

All members of the Compensation Committee during fiscal year 2008 were independent directors, and no member was an employee or former employee. No Compensation Committee member had any relationship requiring disclosure under "Transactions with Related Persons" on page 45. During fiscal year 2008, none of our executive officers served on the compensation committee (or its equivalent) or board of directors of another entity whose executive officer(s) served on our Compensation Committee, any other Board committee, or the Board of Directors as a whole.

Copies of Charters, Guidelines and Code of Ethics

A copy of the current Audit, Compensation, Finance and Corporate Governance and Nominating Committee Charters, as well as our Corporate Governance Guidelines and Code of Ethics, together with any amendments, are available on our Web site at www.UNS.com or may be obtained by shareholders, without charge, upon written request to Library and Resource Center, UniSource Energy Corporation, 3950 East Irvington Road, Mail Stop RC114, Tucson, Arizona 85714.

TRANSACTIONS WITH RELATED PERSONS

Related Person Transactions Policy

In February 2007, the Board adopted a written policy on the review of related person transactions (which is available on our website at www.UNS.com) that specifies that certain transactions involving directors, nominees, executive officers, significant shareholders and certain other related persons in which the Company is or will be a participant and are of the type required to be reported as a related person transaction under Item 404 of Regulation S-K shall be reviewed by the Audit Committee for the purpose of determining whether such transactions are in the best interest of the Company. The policy also establishes a requirement for directors, nominees and executive officers to report transactions involving a related party that exceeds $120,000 in value. We are not aware of any transactions entered into since adoption of the policy that did not follow the procedures outlined in the policy.

On January 29, 2008, the son of one of our directors, Ms. Bilby, was appointed as Chief Financial Officer of Global Solar Energy ("GSE"). GSE had been one of our subsidiaries prior to our sale of GSE in 2006. In connection with the sale of GSE, GSE entered into a lease with our subsidiary Millennium Energy Holdings ("MEH") for the building comprising GSE's manufacturing facility. The lease terminated in September of 2008. The aggregate amount of lease payments made by GSE to MEH in 2008 was $280,000. Ms. Bilby's son had no monetary interest in the lease transaction.

AUDIT COMMITTEE REPORT

The Committee

The Audit Committee is made up of five financially literate directors who are independent based upon independence criteria established by our Board, which criteria are in compliance with applicable NYSE listing standards. Our Board has determined that while each member of the Audit Committee has accounting and/or related financial management expertise, Ms. Baumann is the Audit Committee financial expert for the purposes of Item 407(d)(5) of SEC Regulation S-K. In addition to Ms. Baumann, there are three other financial experts on the Audit Committee. Each financial expert is independent as that term is used in Item 7(d)(3)(iv) of Schedule 14A under the Securities Exchange Act of 1934, as amended. The Board previously adopted a written charter for the Audit Committee. The Audit Committee has complied with its charter, including the requirement to meet periodically with our Independent Registered Public Accounting Firm, internal audit department and management to discuss the auditor's findings and other financial and accounting matters.

In connection with our December 31, 2008 financial statements, the Audit Committee has: (i) reviewed and discussed the audited financial statements with management, (ii) discussed with PricewaterhouseCoopers, LLP, our Independent Registered Public Accounting Firm, the matters required to be discussed by Statement on Auditing Standards No. 61, as amended (AIPCA, Professional Standards, Vol. 1 AU Sec. 380), as adopted by the Public Company Accounting Oversight Board in Rule 3200T, (iii) received from PricewaterhouseCoopers, LLP, the written disclosures and the letter required by applicable requirements of the Public Accounting Oversights Board regarding the Independent Registered Public Accounting Firm's communications with the Audit Committee concerning independence, and (iv) discussed with PricewaterhouseCoopers, LLP its independence.

Based on the review and discussions referred to in items (i) through (iv) of the above paragraph, the Audit Committee recommended to the Board that the audited financial statements for 2008 be included in the annual report on Form 10-K for filing with the SEC.

Pre-Approved Policies and Procedures

Rules adopted by the SEC in order to implement requirements of the Sarbanes-Oxley Act of 2002 require public company audit committees to pre-approve audit and non-audit services. Our Audit Committee has adopted a policy pursuant to which audit, audit-related, tax and other services are pre-approved by category of service. Recognizing that situations may arise where it is in our best interest for the auditor to perform services in addition to the annual audit of our financial statements, the policy sets forth guidelines and procedures with respect to approval of the four categories of service designed to achieve the continued independence of the auditor when it is retained to perform such services for us. The policy requires the Audit Committee to be informed of each service and does not include any delegation of the Audit Committee's responsibilities to management. The Audit Committee may delegate to the Chairman of the Audit Committee the authority to grant pre-approvals of audit and non-audit services requiring Audit Committee approval where the Audit Committee Chairman believes it is desirable to pre-approve such services prior to the next regularly scheduled Audit Committee meeting. The decisions of the Audit Committee Chairman to pre-approve any such services from one regularly scheduled Audit Committee meeting to the next shall be reported to the Audit Committee.

Fees

The following table details fees paid to PricewaterhouseCoopers, LLP for professional services during 2007 and 2008. The Audit Committee has considered whether the provision of services to us by PricewaterhouseCoopers, LLP, beyond those rendered in connection with their audit and review of our financial statements, is compatible with maintaining their independence as auditor.

	2008	2007
Audit Fees	$ 1,692,707	$1,627,888
Audit-Related Fees	$ 50,000	$ 47,500
Tax Fees	$ 0	$ 0
All Other Fees	$ 4,500	$ 3,690
Total	$ 1,747,207	$1,679,078

Audit fees include fees for the audit of our consolidated financial statements included in our annual report on Form 10-K and review of financial statements included in our Quarterly Reports on Form 10-Q. Audit fees also include services provided by PricewaterhouseCoopers, LLP in connection with the audit of the effectiveness of internal control over financial reporting and on management's assessment of the effectiveness of internal control over financial reporting, comfort letters, consents and other services related to SEC matters and financing transactions, statutory and regulatory audits, and accounting consultations to the extent necessary for PricewaterhouseCoopers, LLP to fulfill their responsibilities under generally accepted auditing standards.

Audit-related fees during 2008 and 2007 principally include fees for employee benefit plan audits.

No tax fees, which in the past have included fees for tax compliance, tax advice and tax planning, were incurred during 2007 or 2008.

All other fees consist of fees for all other services other than those reported above and, in 2007 and 2008, principally include subscription fees for research tools and attendance at training courses.

All services performed by PricewaterhouseCoopers, LLP are approved in advance by the Audit Committee in accordance with the Audit Committee's pre-approval policy for services provided by the Independent Registered Public Accounting Firm.

Respectfully submitted,

THE AUDIT COMMITTEE

Barbara M. Baumann, Chair
John L. Carter
Daniel W. L. Fessler
Warren Y. Jobe
Gregory A. Pivirotto

SUBMISSION OF SHAREHOLDER PROPOSALS

General

Rule 14a-4 of the SEC's proxy rules allows us to use discretionary voting authority to vote on a matter coming before an annual meeting of our shareholders, which was not included in our Proxy Statement (if we do not have notice of the matter at least 45 days before the date on which we first mailed our proxy materials for the prior year's annual meeting of the shareholders). In addition, we may also use discretionary voting authority if we receive timely notice of such matter (as described in the preceding sentence) and if, in the Proxy Statement, we describe the nature of such matter and how we intend to exercise our discretion to vote on it. Accordingly, for our 2010 annual meeting of shareholders, any such notice must be submitted to the Corporate Secretary of UniSource Energy, One South Church Avenue, Suite 1820, Tucson, Arizona, 85701, on or before February 10, 2010.

We must receive your shareholder proposals by November 21, 2009.

This requirement is separate and apart from the SEC's requirements that a shareholder must meet in order to have a shareholder proposal included in our Proxy Statement. Shareholder proposals intended to be presented at our 2010 annual meeting of the shareholders must be received by us no later than November 21, 2009 in order to be eligible for inclusion in our Proxy Statement and the form of proxy relating to that meeting. Direct any proposals, as well as related questions, to the undersigned.

DELIVERY OF PROXY MATERIALS TO HOUSEHOLDS

If you and one or more shareholders of Company stock share the same address, it is possible that only one Notice of Internet Availability of Proxy Materials was delivered to your address. This is known as "householding." Any registered shareholder who wishes to receive separate copies of the Notice of Internet Availability of Proxy Materials at the same address now or in the future may call or write the Company's Stock Transfer Agent, BNY/Mellon, toll free at 1-866-537-8709/or BNY Shareowner Services, 480 Washington Blvd – 29th Floor, Jersey City, NJ, 07310. Separate copies of the Notice of Internet Availability of Proxy Materials will be promptly delivered upon receipt of such request.

Shareholders who own Company stock through a broker and who wish to receive separate copies of the Notice of Internet Availability of Proxy Materials should contact their broker.

Any registered shareholder who wishes to receive a single copy of the Notice of Internet Availability of Proxy Materials at the same address now or in the future may call the Company's Stock Transfer Agent, BNY/Mellon, toll free at 1-866-537-8709.

OTHER BUSINESS

The Board knows of no other matters for consideration at the Meeting. If any other business should properly arise, the persons appointed in the enclosed proxy have discretionary authority to vote in accordance with their best judgment.

Copies of our annual report on Form 10-K may be obtained by shareholders, without charge, upon written request to the Library and Resource Center, UniSource Energy Corporation, 3950 East Irvington Road, Mail Stop RC114, Tucson, Arizona 85714. You may also obtain our SEC filings through the Internet at www.sec.gov or www.UNS.com.

By order of the Board of Directors,

Linda Kennedy

Linda H. Kennedy
Corporate Secretary

PLEASE VOTE - YOUR VOTE IS IMPORTANT

**UNS GAS, INC.'S RESPONSE TO
RUCO'S FIRST SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
May 7, 2009**

RUCO 1.94 Identify the amount of fleet fuel expense in the test year and for each of the calendar years 2006, 2007 and 2008. Identify the current cost of fleet fuel as well as the cost of fleet fuel used to calculate fleet expense in the test year.

RESPONSE: Please see the Excel files RUCO 1.94 Test Year, RUCO 1.94 2006, RUCO 1.94 2007 and RUCO 1.94 2008 on the enclosed CD for the amount of fleet fuel expense for the test year, 2006, 2007 and 2008, respectively. The current cost of fleet fuel as of 5-6-09 is an average of $2.09/gallon.

The Excel Files are <u>not</u> identified by Bates numbers.

RESPONDENT: Julie Gomez

WITNESS: Dallas Dukes

SUPPLEMENTAL RESPONSE: The "Miles" column in the Excel file RUCO 1.94 2006 was left blank when submitted to RUCO, without explanation. The reason this column is blank is that in 2006 the UNS Gas vehicles had not been fully loaded into the Tucson Electric Power Fleet Management system. UNS Gas is unable to give an accurate mileage account for 2006. The miles traveled in 2007 should be close to what was traveled in 2006.

RESPONDENT: Gary Kelly

WITNESS: Dallas Dukes

UNS GAS, INC.
CALENDAR YEAR 2006

Source: J. Gomez

Month	Amount	$/Gal	Gallons	Miles
Jan-06	$51,607.67	$2.51	20,562	
Feb-06	$41,820.39	$2.51	16,694	
Mar-06	$48,541.12	$2.59	18,731	
Apr-06	$52,119.78	$2.94	17,743	
May-06	$59,700.07	$3.13	19,073	
Jun-06	$55,163.42	$3.02	18,290	
Jul-06	$56,249.17	$3.01	18,709	
Aug-06	$58,787.62	$2.98	19,698	
Sep-06	$50,196.41	$2.67	18,828	
Oct-06	$42,975.81	$2.45	17,542	
Nov-06	$50,686.13	$3.06	16,567	
Dec-06	$31,243.89	$2.50	12,498	
Totals		**$2.78**	**214,935**	**0**

UNS GAS, INC.
CALENDAR YEAR 2007

Source: J. Gomez

Month	Amount	$/Gal	Gallons	Miles
Jan-07	$45,492.84	$2.42	18,777	287,170
Feb-07	$41,837.05	$2.47	16,937	286,775
Mar-07	$53,673.60	$2.74	19,618	315,877
Apr-07	$53,321.43	$2.99	17,833	332,610
May-07	$58,540.21	$3.09	18,946	273,648
Jun-07	$56,211.24	$3.07	18,310	357,882
Jul-07	$60,051.97	$2.99	20,070	310,803
Aug-07	$55,347.52	$2.84	19,460	352,954
Sep-07	$49,526.26	$2.84	17,468	281,905
Oct-07	$55,776.30	$2.99	18,625	299,792
Nov-07	$55,464.72	$3.25	17,086	328,348
Dec-07	$50,490.71	$3.21	15,717	179,787
Totals		**$2.91**	**218,847**	**3,607,551**

Month	Amount	$/Gal	Gallons	Miles
Jan-08	$70,175.96	$3.16	22,234	216,237
Feb-08	$60,357.91	$3.25	18,597	220,381
Mar-08	$64,770.37	$3.56	18,173	207,156
Apr-08	$70,034.64	$3.72	18,840	178,971
May-08	$76,492.80	$4.04	18,942	200,136
Jun-08	$63,602.51	$4.33	14,687	183,716
Jul-08	$80,189.92	$4.30	18,641	171416
Aug-08	$70,220.72	$3.96	17,712	210901
Sep-08	$67,637.02	$3.77	17,924	166329
Oct-08	$59,430.74	$3.24	18,345	217413
Nov-08	$38,344.82	$2.50	15,368	147355
Dec-08	$27,617.38	$2.03	13,611	194943
Totals		**$3.49**	**213,074**	**2,314,954**

Tribune
EAST VALLEY · SCOTTSDALE

May 19, 2009

Gas prices on the rise for summer driving

By Edward Gately
Tribune

Mesa resident James Lowery fills up at Mobil on Baseline and Stapley Roads in Mesa.

Tribune

The past week's jump in gas prices no doubt has many East Valley motorists fearing another price escalation is on its way this summer.

However, prices aren't likely to match last summer's record-setting climb, said Michelle Donati, AAA Arizona spokeswoman. The current statewide average for a gallon of regular unleaded gas is $2.10, an increase of about 18 cents over the past month, she said.

"However, we are still paying $1.48 less per gallon than we were paying this time last year," she said.

The price increase can be attributed in part to the transition to the summer fuel blend, which is cleaner burning and more expensive to produce, Donati said. Also, oil prices have increased from the low $50s range for a barrel to the high $50s range for a barrel, she said.

"Those increased crude costs have resulted in higher wholesale costs for gasoline, which has had an adverse effect on retail margins, so all of that trickles down to higher pump prices for consumers," she said.

Last year when prices were reaching $4 a gallon and beyond, crude oil was trading at more than double what it is now, Donati said.

In the meantime, Arizona continues to have the lowest gas prices in the country, she said.

Nationally, gas prices could hit $2.50 a gallon this summer, said Tom Kloza, publisher and chief oil analyst at Oil Price Information Service.

"I think that the average price in the country will soon flirt with $2.40 a gallon, which is higher than what I projected through the first four months of this year," he said. "I think that those average prices may even flirt with $2.50 a gallon, but that would be quite frothy. It would shock me if we see prices in any metropolitan area in the $3.00 a gallon plus range."

Arizona's prices should remain 10 to 15 cents below the national averages, which means "you may see summer driving season numbers in the $2.10-$2.35 a gallon range," Kloza said.

U.S. demand for fuel remains poor, with at least 2.5 million barrels per day of extra U.S. refining capability on the shelf, Kloza said. Unemployment has stifled much of the work-related driving, and gasoline imports promise to displace plenty of U.S.-produced fuel from June through December, he said.

"Ultimately, these factors point toward prices not matching the high numbers witnessed in 2005, 2006, 2007 or in the first 10 months of 2008," he said.

The recent jump in gas prices aren't expected to keep many Arizonans from hitting the road this Memorial Day, according to AAA Arizona. An estimated 761,000 Arizonans are projected to travel 50 or more miles from home over the first summer holiday weekend, a 2.5 percent decrease from last year.

"We're still anticipating that a really healthy number of holiday travelers will be doing so by way of motor vehicle, and that's because in most cases auto travel is still the most economical mode of travel," Donati said.

In the Mesa 85201 zip code, for example, the cost of filling a 15-gallon tank now averages $31.62. A year ago, doing so would have cost $54.36.

"That means that for every tank of gas you're filling up right now in that area code, you're paying almost $23 less," Donati said. "Given that prices have come up in the past couple of weeks, since they are still significantly lower than they were this time last year, we're not anticipating that gas prices alone will have an adverse effect on motor vehicle travel."

Motorists won't encounter any construction-related road closures this weekend, said Doug Nintzel, Arizona Department of Transportation spokesman.

"We would expect that State Route 87 as well as Interstate 17 will be busy on Friday afternoon and also on Monday afternoon when folks are returning from trips to the high country," he said. "We recommend that drivers be patient, avoid tailgating and expect the unexpected by bringing some extra drinking water and snacks just in case there's an unscheduled closure."

FREEDOM
COMMUNICATIONS, INC

AAA's Daily Fuel Gauge Report *The most comprehensive nationwide fuel price survey available from any source.*

AAA OPIS Method FAQs Commentary State Prices AAA Maps Links En Español Select A Market

Prices updated as of 6/3/2009 2:59:05 AM

Data provided by Oil Price Information Service *in cooperation with* Wright Express
Media are encouraged to localize fuel price stories by contacting their local AAA club media representative.

Arizona Average Prices

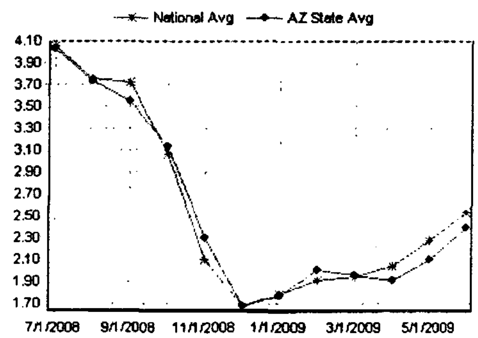
	Regular	Mid	Premium	Diesel
Current Avg.	$2.405	$2.508	$2.653	$2.397
Yesterday Avg.	$2.381	$2.483	$2.626	$2.369
Week Ago Avg.	$2.287	$2.385	$2.523	$2.307
Month Ago Avg.	$1.902	$1.983	$2.097	$2.202
Year Ago Avg.	$3.889	$4.056	$4.289	$4.787

View Arizona Metro Areas

Highest Recorded Average Price:

Regular Unl.	$4.090	7/3/2008
DSL.	$4 855	7/9/2008

12 Month Average For Regular



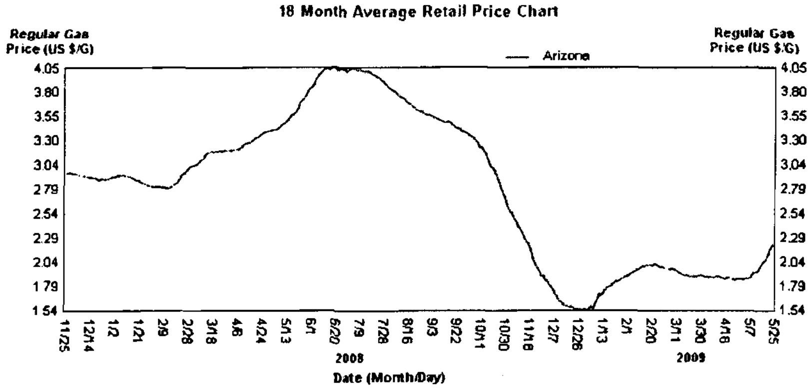
For information on automotive fuel issues, including AAA's recommendations regarding fuel conservation, click here.

AAA's Daily Fuel Gauge Report is updated daily and is the most comprehensive retail gasoline survey available. Every day over 100,000 self-serve stations are surveyed.

Historical Price Charts

Quick charts: 1 Month | 3 Month | 6 Month | 9 Month | 1 Year | 18 month | 2 Years | 3 Years | 4 Years | 5 Years | 6 Years

18 Month Average Retail Price Chart



Add these dynamic charts to your website

Customize Price Charts

Area 1: Arizona, AZ Time Period: 18 Month US $/G Create Chart

Area 2: Show Crude Oil Price Canadian c/L

Area 3:

Step One - Select a single city in order to identify price trends or to identify a historical price most accurately. Select multiple cities to compare pump prices between cities.

Step Two - Selection of time duration will define how long into history the prices will be displayed. In some cities only limited price history information is available and in those cases the line will be flat for extended periods.

Step Three - When comparing US cities to Canadian cities you have a choice of price units. The standard unit of measure in the US is dollars per gallon and in Canada the standard is cents/liter. Comparison of US and Canadian cities is done using recent currency exchange rates and uses the conversion factor of 1 US gallon being equal to 3.78 liters. For simple plotting of US cities use dollars per gallon ($/G) and for simple plotting of Canadian cities use cents/liter (c/L).

Step Four - Click the "Create Chart!" button to create the chart

How GasBuddy Works

You spot gas prices

Report your prices

Earn points & win prizes

Help everyone save on gas

Learn More >>

Local Price Snapshot

Today	2.278
Yesterday	2.291
One Week Ago	2.203
One Month Ago	1.876
One Year Ago	3.797

Trend

Prices Falling

[Points Leaders]

Prize Give-Away!

We're giving away a $250 gas card every week!

Next Draw Sunday, May 31, 2009

Learn More Get Tickets

Sponsored by GasBuddy.com

See Prize Winners

Regular Gas | Midgrade | Premium | Diesel Fuel

Lowest Regular Gas Prices in the Last 48 Hours

Price	Station	Area	Time	Thanks
2.05	Costco 3911 E AZ-69 & Walker Rd	Prescott	Thu 12:30 PM	WingLeader
2.07	ARCO 286 Walker Rd & E AZ-69	Prescott	Thu 12:30 PM	WingLeader
2.07	Sam's Club E AZ-69 & Sundog Ranch Rd	Prescott Valley	Thu 12:30 PM	WingLeader
2.09	Fastrip 1131 AZ-95 & 3rd St	Bullhead City	Thu 9:23 AM	REBELJACK
2.12	Conoco 1981 E Deuce of Clubs near E Adams	Show Low	Fri 2:51 AM	Stoneys
2.15	ARCO 311 Lake Havasu Ave N & Palo Verde Blvd S	Lake Havasu City	Thu 6:41 AM	seadoo27
2.16	Safeway 900 W Deuce of Clubs & S8thAve	Show Low	Fri 2:51 AM	Stoneys
2.17	Maverik 901 N Penrod Rd & US-60	Show Low	Fri 2:51 AM	Stoneys
2.18	ARCO 4670 E US-60 near Ragus Rd	Claypool	Thu 2:47 PM	zeegirl116
2.19	Maverik 2197 McCulloch Blvd & ACOMA Blvd	Lake Havasu City	Fri 7:36 AM	cnet1
2.19	Smith's 80 Acoma Blvd N & Mesquite Ave	Lake Havasu City	Fri 7:36 AM	cnet1
2.19	Maverik 2197 McCulloch Blvd N & Acoma Blvd N	Lake Havasu City	Fri 6:15 AM	seadoo27
2.19	Zip 54 Lake Havasu Ave N & Mesquite Blvd	Lake Havasu City	Fri 6:15 AM	seadoo27
2.19	Gas N Go 1730 N Broad St near N Main St (US 60)	Globe	Thu 2:47 PM	zeegirl116
2.19	Maverick AZ-87 N	Payson	Wed 11:09 PM	screechhawk_1

Add this list of current gas prices to your website

Highest Regular Gas Prices in the Last 48 Hours

Price	Station	Area	Time	Thanks
2.89	Shell 640 S AZ-90 & E Hamilton Ln	Benson	Thu 10:14 AM	Dragnet
2.69	Shell 14905 S Stagecoach Tr near I-17 Exit 262 (Phone 928-632-4521)	Cordes Junction	Thu 12:21 AM	Army2310
2.69	Chevron 19625 E Cordes Lakes Rd & I-17 exit 262 (Phone 928-632-8558)	Cordes Junction	Thu 12:21 AM	Army2310
2.51	Shell B-10 & US-95	Quartzsite	Thu 8:12 PM	spheremaker1

Search For Gas Prices

Regular Mid Premium Diesel

Arizona Site Only All of Arizona

Area: All Areas, Ajo, Alpine, Arizona City, Avra Valley

Station: All Stations, 7-Eleven, 76, AAFES, Albertsons

Hold Ctrl to select multiple areas/stations)

Other Area Prices in the last 48 hours

Search Now! [Top Low & High Prices]

Quick Search for Gas Prices

Find the lowest gas prices in these areas:
Bullhead City Casa Grande Douglas Eloy Flagstaff Florence Kingman Lake Havasu City Nogales Payson Prescott Prescott Valley San Luis Sierra Vista Yuma [More Cities]

Arizona Gas Prices

When you enter a gas price into the above form, you are assisting in the fight against high gasoline prices in Arizona. Together we can work to promote competition and drive down the retail price of gasoline.

Not from Arizona? Try one of these www.GasBuddy.com gas prices sites:

Metro Areas OR States/Provinces Go!

Tell a friend about our site!

Friend's Email Your Name (Advanced) Continue

Unleaded Gasoline Average Prices

	Arizona	USA	Trend
Today	2.278	2.466	
Yesterday	2.291	2.454	

UNS GAS, INC.'S RESPONSE TO STAFF'S FIFTH SET OF DATA REQUESTS DOCKET NO. G-04204A-08-0571 April 16, 2009

TF 6.68 As the Company discovers errors in its filing identify such errors and provide documentation to support any changes. Please update this response as additional information becomes available.

RESPONSE: Rate Case Expense Pro Forma Adjustment: this pro forma adjusted test year rate case expense and was composed of an estimate of rate case expense in the current docket and an adjustment related to rate case expense approved in Decision No. 70011 (November 27, 2007). The original adjustment as identified by Bates Nos. UNSG(0571)02687 to UNSG(0571)02688 and the associated Excel file not identified by Bates numbers (both provided in response to Staff Data Request JMK-1.1) requires a correction for an additional adjustment to test year expense that was overlooked. The additional adjustment is to remove test year amortization of rate case expense for $200,000 of the $300,000 allowed in Decision No. 70011 for the 2006 rate case that will be recovered prior to new rates becoming effective, resulting in a reduction of test year expense of $58,333.

Please see the Excel workbook TF 6.68 (Income - Rate Case Expense 6-30-08 Corrected) on the enclosed CD.

The Excel file on the CD is not identified by Bates numbers.

RESPONDENT: Janet Zaidenberg-Schrum

WITNESS: Dallas Dukes

UNS GAS, INC.
RATE BASE PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2008

CORRECTED PRO FORMA ADJUSTMENT FOR STAFF DATA REQUEST TF 6.68

ADJUSTMENT NAME:	Rate Case Expense
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	April 8, 2009
PREPARED BY:	Janet Zaidenberg-Schrum
CHECKED BY:	Mina Briggs
REVIEWED BY:	Dallas Dukes

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
928	Regulatory Expense (A)	$33,333	
928	Regulatory Expense (B)	$166,667	
407	**Amortization of Regulatory Assets - Rate Case Expense**		**$58,333**
	ENTRY TOTAL	**$200,000**	**$58,333**
	NET ENTRY	**$141,667**	

<u>Reason for Adjustment</u>

A) To include rate case expense approved in ACC Decision No. 70011 for the 2006 rate case.

B) To include an estimate of outside expenditures for the rate case expense amortization for $500,000 total expense amortized over 3 years @ $166,667 per year.

<u>Addition to Original Pro Forma to correct test year expense</u>

C) To remove test year amortization of rate case expense for $200,000 of the $300,000 allowed in ACC Decision No. 70011 for the 2006 rate case that will be recovered prior to new rates becoming effective.

<u>Note</u>: Pro forma adjustments related to the write-off 2006 rate case expense not included in the $300,000 allowed in ACC Decision No. 70011 are included in the pro forma adjustment for Miscellaneous Expenses.

UNS Gas, Inc.
Rate Case Expense Per ACC Decision No. 70011
Test Year Ended June 30, 2008

Rate Case Expense allowed per ACC Decision No. 70011		$300,000
Yearly Amortization (starting December 2007)		$100,000
Monthly Amortization (starting December 2007)		$8,333
Amortization December 2007 - November 2009 (24 months)	\1	$200,000
Remaining Balance @ November 30, 2009		$100,000
Amortization for Test Year Balance @ November 30, 2009 over 3 years		$33,333

\1 Assumption: new rates will go into effect 14 months after the rate case is filed in October 2008 (in effect as of December 1, 2009).

Correction of original pro forma	
Assumptions for recovery of $300k	
Rates in effect 12/1/07 through 11/30/09 = 24 months	
24 months of rate case expense recovery =	$200,000
Monthly rate case expense recovery over 24 months	$8,333
Rate case expense in test year - to be removed	**$58,333**
Remaining expense to be recovered over 3 more years	$100,000
New rates in effect 12/1/09 - 11/30/12 = 36 months	
Yearly rate case expense recovery of $100k over3 years	$33,333
Monthly rate case expense recovery of $100k over 36 months	$2,778

**UNS GAS, INC.'S RESPONSE TO
RUCO'S FIRST SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
May 7, 2009**

RUCO 1.90 Refer to K. Kissenger's testimony, page 8.

a. What is the 2008 statutory assessment ratio?

b. Provide the most current known average property tax rates used. Identify and provide a copy of the source

RESPONSE:

a. The 2008 statutory assessment ratio is 23%.

b. The most current average known property tax rate is for the 2008 tax year. That rate is 7.6127%. The calculation of the rate is shown in the PDF file RUCO 1.90, Bates Nos. UNSG(0571)09064, on the enclosed CD. The source of the individual rates for each tax district is the property tax bills sent by the counties. There are hundreds of these bills so they have not been included in the supporting attachments. A review of the bills for the 2008 tax year can be arranged at a mutually agreed upon time and place, if necessary.

RESPONDENT: Gail Boswell

WITNESS: Karen Kissinger

UNS Gas, Inc.

Tax Year 2008

Average Property Tax Rate

County	Full Cash Value	Taxable Value	Property Tax	Avg Tax Rate
Coconino	25,213,370	5,799,075	434,457	7.4918%
Mohave	18,447,130	4,242,840	292,896	6.9033%
Navajo	20,920,491	4,811,713	384,561	7.9922%
Santa Cruz	7,296,504	1,678,196	179,004	10.6664%
Yavapai	57,176,173	13,150,520	968,709	7.3663%
Total	*129,053,668*	*29,682,344*	*2,259,626*	*7.6127%*

UNS Gas, Inc.
Pro Forma ADIT - Summary
Test Year Ended 6/30/2008
\\Cds_1\corpdata\TAXSVCS\Rate Cases\UNSG\2008 06-30 TY\ADIT\[UNSG ADIT TY 06-30-08.xls]A1 - Summary

		ADIT Per Financial Statements		Pro Forma ADIT	Change in ADIT
Account 190					
Bad Debt	G1.1-G1.2	463,156		-	(463,156)
CIAC	G1.1-G1.2	2,724,268	E1.1a	2,436,909	(287,359)
Customer Advances	G1.1-G1.2	4,970,984	F1.1a	4,402,955	(568,029)
Customer Advances - CWIP	G1.1-G1.2	-	I1A	(227,413)	(227,413)
Dividend Equivalents	G1.1-G1.2	18,417	*	17,952	(465)
DSM Adjustor	G1.1-G1.2	55,568			(55,568)
FAS 106	G1.1-G1.2	1,054			(1,054)
FAS 112	G1.1-G1.2	30,983		-	(30,983)
Incentive Comp PEP	G1.1-G1.2	(818)		-	818
Other Comprehensive Income FAS 106	G1.1-G1.2	(19,820)		-	19,820
Restricted Stock	G1.1-G1.2	24,946	*	24,316	(630)
Restricted Stock - Directors	G1.1-G1.2	56,713	*	55,281	(1,432)
Stock Options	G1.1-G1.2	159,742	*	155,708	(4,034)
Vacation	G1.1-G1.2	173,755	*	169,367	(4,388)
Total Account 190		8,658,948		7,035,076	(1,623,872)
Account 282					
Net Plant ADIT	G1.1-G1.2	(20,473,284)	B1.1a+B2.1a	(17,452,856)	3,020,428
~~Net CWIP ADIT~~	G1.1-G1.2	(162,379)	C7.3i	-	162,379
Total Account 282		(20,635,663)		(17,452,856)	3,182,807
Account 283					
CARES Reg Asset	G1.1-G1.2	(195,073)	H1.1A	(190,140)	4,933
OCI-Cash Flow Hedge Gas Cur		(1,559,519)			1,559,519
OCI-Cash Flow Hedge Gas NC		(1,367,888)			1,367,888
Pension	G1.1-G1.2	1,072	*	1,045	(27)
Rate Case Expenses	G1.1-G1.2	(153,949)		-	153,949
SERP	G1.1-G1.2	195,089		-	(195,089)
Total Account 283		(3,080,268)		(189,095)	2,891,173
Grand Total		(15,056,983)		(10,606,875)	4,450,108

*Adjsuted from 39.6% tax rate used for income tax accounting to 38.6% tax rate used for ratemaking.

ACCOUNTING DEPARTMENT
Prepared by MBcyl 10-8-2008
Checked by [illegible] 10/10/08
Approved by
Input by
Other side of I/C in J#____ by ____

UNS Gas, Inc.
Test Year Ended June 30, 2008
Depreciation & Amortization Expense by Plant FERC account

From Revenue Requirement Model (data from Plant Accounting)

					C	D				E	A
Function	**Plt Acct & Desc**	**0403**	**0404**	**Total 403 & 404**	**% 403 of Total**	**% 404 of Total**	**0406**	**Total**	**Citizens Acq Discount 0406**	**Citizens Acq % 406 of Total**	**So Union Acq Premium 0406**
Intangible	302-Franchise	0.00	15,574.49	15,574.49	0.00%	1.26%	(2,398.42)	13,176.07	(3,224.55)	0.1827%	826.13
Intangible	303-Intangibles	0.00	1,218,556.40	1,218,556.40	0.00%	98.74%	4,042.39	1,222,598.79	(4,423.65)	0.2507%	8,466.04
		0.00	1,234,130.89	1,234,130.89			1,643.97	1,235,774.86	(7,648.20)		9,292.17
Transmission	365-Land & Land Rights	826.00	0.00	826.00	0.01%	0.00%	(276.57)	549.43	(276.57)	0.0157%	0.00
Transmission	366-Struct & Imprv	662.89	0.00	662.89	0.01%	0.00%	(206.04)	456.85	(206.04)	0.0117%	0.00
Transmission	367-Mains	343,544.57	0.00	343,544.57	4.12%	0.00%	(55,515.44)	288,029.13	(55,515.44)	3.1456%	0.00
Transmission	369-Meas & Reg St Eq	56,068.22	0.00	56,068.22	0.67%	0.00%	(14,831.21)	41,237.01	(14,831.21)	0.8404%	0.00
Transmission	371-Other Eq	6,491.11	0.00	6,491.11			(1,904.59)	4,586.52	(1,904.59)	0.1079%	0.00
		407,592.79	0.00	407,592.79			(72,733.85)	334,858.94	(72,733.85)		0.00
Distribution	374-Land & Land Rights	1,213.73	0.00	1,213.73	0.01%	0.00%	(406.35)	807.38	(406.35)	0.0230%	0.00
Distribution	375-Struct & Imprv	203.85	0.00	203.85	0.00%	0.00%	(13.93)	189.92	(13.93)	0.0008%	0.00
Distribution	376-Mains	3,527,325.90	0.00	3,527,325.90	42.26%	0.00%	(570,388.01)	2,956,937.89	(822,542.94)	46.6072%	252,154.93
Distribution	378-Meas & Reg St Eq	72,346.23	0.00	72,346.23	0.87%	0.00%	(6,460.40)	65,885.83	(12,595.73)	0.7137%	6,135.33
Distribution	379-Meas & Reg St Eq (City)	69,689.58	0.00	69,689.58	0.83%	0.00%	(6,325.33)	63,364.25	(12,656.07)	0.7171%	6,330.74
Distribution	380-Services	2,442,227.93	0.00	2,442,227.93	29.26%	0.00%	(317,309.45)	2,124,918.48	(421,361.85)	23.8754%	104,052.40
Distribution	381-Meters	274,799.83	0.00	274,799.83	3.29%	0.00%	(35,276.43)	239,523.40	(52,550.95)	2.9777%	17,274.52
Distribution	382-Meter Install	203,625.88	0.00	203,625.88	2.44%	0.00%	(39,449.54)	164,176.34	(39,595.85)	2.2436%	146.31
Distribution	383-House Reg	74,055.60	0.00	74,055.60	0.89%	0.00%	(13,183.45)	60,872.15	(10,307.79)	0.5841%	(2,875.66)
Distribution	384-House Reg Install	38,170.86	0.00	38,170.86	0.46%	0.00%	(5,152.66)	33,018.20	(5,152.66)	0.2920%	0.00
Distribution	385-Indust Meas & Reg St Eq	22,288.80	0.00	22,288.80	0.27%	0.00%	939.91	23,228.71	(6,311.64)	0.3576%	7,251.55
Distribution	387-Other Eq	(13,425.15)	0.00	(13,425.15)	-0.16%	0.00%	(3,749.90)	(17,175.05)	(9,967.66)	0.5648%	6,217.76
		6,712,523.04	0.00	6,712,523.04			(996,775.54)	5,715,747.50	(1,393,463.42)		396,687.88
General	389-Land & Land Rights	923.44	0.00	923.44	0.01%	0.00%	761.46	1,684.90	(2,791.40)	0.1582%	3,552.86
General	390-Struct & Imprv	231,073.72	0.00	231,073.72	2.77%	0.00%	(4,443.67)	226,630.05	(12,094.87)	0.6853%	7,651.20
General	391-Furn & Eq	672,571.67	0.00	672,571.67	8.06%	0.00%	(210,366.77)	462,204.90	(211,304.61)	11.9730%	937.84
General	392-Transp Eq	(19,662.42)	0.00	(19,662.42)	-0.24%	0.00%	0.00	(19,662.42)	0.00	0.0000%	0.00
General	393-Stores Eq	5,450.95	0.00	5,450.95	0.07%	0.00%	(393.79)	5,057.16	(1,159.99)	0.0657%	766.20
General	394-Tools, Shp & Gar	86,577.50	0.00	86,577.50	1.04%	0.00%	(3,119.67)	83,457.83	(19,782.04)	1.1209%	16,662.37
General	395-Lab Eq	75,252.83	0.00	75,252.83	0.90%	0.00%	(18,232.75)	57,020.08	(18,232.75)	1.0331%	0.00
General	396-Power Op Eq	100,257.71	0.00	100,257.71	1.20%	0.00%	(2,106.11)	98,151.60	(979.19)	0.0555%	(1,126.92)
General	397-Comm Eq	69,771.46	0.00	69,771.46	0.84%	0.00%	(22,008.84)	47,762.62	(22,008.84)	1.2471%	0.00
General	398-Misc Eq	11,248.18	0.00	11,248.18	0.13%	0.00%	(2,669.73)	8,578.45	(2,640.57)	0.1496%	(29.16)
		1,233,465.04	0.00	1,233,465.04			(262,579.87)	970,885.17	(290,994.26)		28,414.39
	Total	8,353,580.87	1,234,130.89	9,587,711.76	100.00%	100.00%	(1,330,445.29)	8,257,266.47	E (1,764,839.73)	100.00%	434,394.44 B
	Excluding FERC 371 (Griffith Plant)	8,347,089.76	1,234,130.89								

Y2K Amortization (FERC 407)	76,752.96	76,752.96
CARES Asset Amortization (FERC 407)	56,932.52	56,932.52
Rate Case Expense Amortization (FERC 407)	58,333.31	58,333.31
Prescott Building Gain Amortization (FERC 407)	(11,815.30)	(11,815.30)
Total FERC 407	180,203.49	180,203.49
Total Depreciation & Amortization Expense	9,767,915.25	8,437,469.96

Ties to income statement

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2

UNS GAS, INC.

INCOME STATEMENT PRO FORMA ADJUSTMENT

TEST YEAR ENDED SEPTEMBER 30, 2007

ADJUSTMENT NAME:	Depr & Amort Annualization - Detail by FERC Account
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	October 21, 2008
PREPARED BY:	Janet Zaidenberg-Schrum
CHECKED BY:	Mina Briggs
REVIEWED BY:	Dallas Dukes

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
A. FERC 403 & 404			
302	Franchises and Consents		$50
303	Miscellaneous Intangible Plant		$3,883
365	Land & Land Rights		$72
366	Structures & Improvements		$58
367	Mains		$30,068
369	Measuring and Reg. Station Equipment		$4,907
371	Other Equipment (Griffith)		$6,491
374	Land, Land Rights, Easements		$106
375	Structures & Improvements		$18
376	Mains		$308,724
378	Meas. and Reg. Station Equipment - General		$6,332
379	Meas. and Reg. Station Equipment - City Gate Check Station		$6,099
380	Services		$213,752
381	Meters		$24,051
382	Meter Installations		$17,822
383	House Regulators		$6,482
384	House Regulatory Installations		$3,341
385	Industrial Meas. & Reg. Station Equipment		$1,951
387	Other Equipment	$1,175	
389	Land & Land Rights		$81
390	Structures & Improvements		$20,224
391	Office Furniture and Equipment		$58,866
392	Transportation Equipment	$1,721	
393	Stores Equipment		$477
394	Tools, Shop and Garage Equipment		$7,578
395	Laboratory Equipment		$6,586
396	Power Operated Equipment		$8,775
397	Communication Equipment		$6,107
398	Miscellaneous Equipment		$984
	Total Annualization - FERC 403 & 404	**$2,896**	**$743,885**
	Net Adjustment - *Annualization*		**$740,989**

UNS GAS, INC.

INCOME STATEMENT PRO FORMA ADJUSTMENT

TEST YEAR ENDED SEPTEMBER 30, 2007

ADJUSTMENT NAME:	Depr & Amort Annualization - Detail by FERC Account
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	October 21, 2008
PREPARED BY:	Janet Zaidenberg-Schrum
CHECKED BY:	Mina Briggs
REVIEWED BY:	Dallas Dukes

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
A. FERC 406 - Citizens Acquisition Discount			
302	Franchises and Consents	$1,731	
303	Miscellaneous Intangible Plant	$2,375	
365	Land & Land Rights	$148	
366	Structures & Improvements	$111	
367	Mains	$29,802	
369	Measuring and Reg. Station Equipment	$7,962	
371	Other Equipment	$1,022	
374	Land, Land Rights, Easements	$218	
375	Structures & Improvements	$7	
376	Mains	$441,561	
378	Meas. and Reg. Station Equipment - General	$6,762	
379	Meas. and Reg. Station Equipment - City Gate Check Station	$6,794	
380	Services	$226,197	
381	Meters	$28,211	
382	Meter Installations	$21,256	
383	House Regulators	$5,533	
384	House Regulatory Installations	$2,766	
385	Industrial Meas. & Reg. Station Equipment	$3,388	
387	Other Equipment	$5,351	
389	Land & Land Rights	$1,498	
390	Structures & Improvements	$6,493	
391	Office Furniture and Equipment	$113,433	
393	Stores Equipment	$623	
394	Tools, Shop and Garage Equipment	$10,619	
395	Laboratory Equipment	$9,788	
396	Power Operated Equipment	$526	
397	Communication Equipment	$11,815	
398	Miscellaneous Equipment	$1,418	
	Total Annualization - Citizens Discount FERC 406	**$947,408**	**$0**
	Net Adjustment - Annualization	**$947,408**	

UNS GAS, INC.

INCOME STATEMENT PRO FORMA ADJUSTMENT

TEST YEAR ENDED SEPTEMBER 30, 2007

ADJUSTMENT NAME:	Depr & Amort Annualization - Detail by FERC Account
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	October 21, 2008
PREPARED BY:	Janet Zaidenberg-Schrum
CHECKED BY:	Mina Briggs
REVIEWED BY:	Dallas Dukes

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
B. FERC 406 - Southern Union Acquisition Premium			
302	Franchises and Consents		$826
303	Miscellaneous Intangible Plant		$8,466
376	Mains		$252,155
378	Meas. and Reg. Station Equipment - General		$6,135
379	Meas. and Reg. Station Equipment - City Gate Check Station		$6,331
380	Services		$104,052
381	Meters		$17,275
382	Meter Installations		$146
383	House Regulators	$2,876	
385	Industrial Meas. & Reg. Station Equipment		$7,252
387	Other Equipment		$6,218
389	389-Land & Land Rights		$3,553
390	Structures & Improvements		$7,651
391	Office Furniture and Equipment		$938
393	Stores Equipment		$766
394	Tools, Shop and Garage Equipment		$16,662
396	Power Operated Equipment	$1,127	
398	Miscellaneous Equipment	$29	
	Total Southern Union	**$4,032**	**$438,426**
	Net Adjustment - Southern Union FERC 406		**$434,394**
	ENTRY TOTAL	**$954,335**	**$1,182,311**
	NET ENTRY		**$227,976**

Reason for Adjustment

A. To adjust test year recorded depreciation and amortization expense to reflect the final adjusted balances of Plant in Service and the Acquisition Discount/Premium and the depreciation rates produced by Dr. White's study.

B. To remove the Southern Union Acquisition Premium amortization expense - premium is excluded from rate base.

UNS GAS, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2008

ADJUSTMENT NAME:	Depreciation Annualization
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	October 9, 2008
PREPARED BY:	E. Fowler
CHECKED BY:	D. Grant
REVIEWED BY:	C. Dabelstein

Revised to break out Acquisition Adjustment pro forma into Citizens & Southern Union

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
403	Depreciation Expense		$737,057
404	Amortization of Utility Plant		$3,933
	Net Depreciation & Amortization Adjustment		$740,990
406	Amortization of Utility Plant Acquisition Adjustments - Citizens	$947,408	
406	Amortization of Utility Plant Acquisition Adjustments - So. Union		$434,394
	Net Amortization Adjustment - Acquisition Adj.	$513,013	
	ENTRY TOTAL	**$947,408**	**$1,175,384**
	NET ENTRY		**$227,976**

<u>Reason for Adjustment</u>

To adjust test year recorded depreciation and amortization expense to reflect the final adjusted balances of Plant in Service and the Acquisition Discount/Premium and the depreciation rates produced by Dr. White's

UNS Gas, Inc.
Depreciation Annualization Adjustment

	A	B	C = A+B	D	E	F = D+E	Calc = C * D	Calc = C * E	Calc = C * F					
Description	Balance at 6/30/08	Rate Case Adjustments	Adjusted Balance	Investment Rate	Cost of Removal	Depreciation Rate %	Investment Rate Component	Cost of Removal Component	Annualized Depreciation	FERC 403 %	Alloc of Adj to FERC 403	FERC 404 %	Alloc of Adj to FERC 404	Total FERC 403 & 404
Intangible Plant:														
Acct. 302 Franchises and Consents	362,992	-	362,992	4.00%		4.00%	14,520	-	14,520	0.00%	-	1.26%	(50)	(50)
Acct. 303 Misc. Intangible Plant	777,500	-	777,500	6.67%		6.67%	51,859	-	51,859	0.00%	-	98.74%	(3,883)	(3,883)
Total	1,140,492	-	1,140,492				66,379	-	66,379					
Transmission Plant:														
Acct. 365 Land Rights of Way	102,606	(16,533)	86,073	1.38%		1.38%	1,188	-	1,188	0.01%	(72)	0.00%	-	(72)
Acct. 366 Structures & Improvements	16,853	(1,061)	15,792	1.55%		1.55%	245	-	245	0.01%	(58)	0.00%	-	(58)
Acct. 367 Mains	22,312,011	(4,825,131)	17,486,880	1.40%	0.13%	1.53%	244,816	22,733	267,549	4.12%	(30,068)	0.00%	-	(30,068)
Acct. 369 Measuring and Regulating Station Equipment	3,574,097	(2,782,032)	792,065	1.46%	0.08%	1.54%	11,564	634	12,198	0.67%	(4,907)	0.00%	-	(4,907)
Acct. 371 Other Equipment (Griffith Plant)	183,581	(183,581)	-	2.49%		2.49%	-	-	-		(6,491)			(6,491)
Total	26,189,148	(7,808,338)	18,380,810				257,813	23,367	281,180					
Distribution Plant:														
Acct. 374 Land	127,927	(8,051)	119,876	0.00%		0.00%	-	-	-					
Acct. 374 Land Rights of Way	25,111	(1,580)	23,531	0.93%		0.93%	219	-	219					
Acct. 374 Easements	104,951	(6,604)	98,347	1.76%		1.76%	1,731	-	1,731	0.01%	(106)	0.00%	-	(106)
Acct. 375 Structures & Improvements	10,948	(689)	10,259	1.93%		1.93%	198	-	198	0.00%	(18)	0.00%	-	(18)
Acct. 376 Mains	170,344,633	(13,217,236)	157,127,397	1.72%	0.35%	2.07%	2,702,591	549,946	3,252,537	42.26%	(308,724)	0.00%	-	(308,724)
Acct. 378 Measuring and Regulating Station Equipment - General	2,501,503	(157,421)	2,344,082	2.29%	0.68%	2.97%	53,679	15,939	69,618	0.87%	(6,332)	0.00%	-	(6,332)
Acct. 379 Measuring and Regulating Station Equipment - City Gate	3,789,758	(1,352,687)	2,437,071	2.36%		2.36%	57,515	-	57,515	0.83%	(6,099)	0.00%	-	(6,099)
Acct. 380 Services	86,176,958	271,433	86,448,391	1.39%	1.43%	2.82%	1,201,633	1,236,212	2,437,845	29.26%	(213,752)	0.00%	-	(213,752)
Acct. 381 Meters	13,780,226	-	13,780,226	2.02%		2.02%	278,361	-	278,361	3.29%	(24,051)	0.00%	-	(24,051)
Acct. 382 Meter Installations	8,633,492	-	8,633,492	2.36%		2.36%	203,750	-	203,750	2.44%	(17,822)	0.00%	-	(17,822)
Acct. 383 House Regulators	2,886,748	-	2,886,748	2.56%		2.56%	73,901	-	73,901	0.89%	(6,482)	0.00%	-	(6,482)
Acct. 384 House Regulator Installations	1,352,659	-	1,352,659	2.80%		2.80%	37,874	-	37,874	0.46%	(3,341)	0.00%	-	(3,341)
Acct. 385 Industrial Measuring and Regulating Station Equipment	1,445,920	(12,609)	1,433,311	1.83%	0.87%	2.70%	26,229	12,470	38,699	0.27%	(1,951)	0.00%	-	(1,951)
Acct. 387 Other Work Equipment	1,141,520	(71,836)	1,069,684	3.01%		3.01%	32,197	-	32,197	-0.16%	1,175	0.00%	-	1,175
Total	292,322,354	(14,557,280)	277,765,074				4,669,878	1,814,567	6,484,445					

	A	B	C = A+B	D	E	F = D+E	Calc = C * D	Calc = C * E	Calc = C * F					
Description	Balance at 6/30/08	Rate Case Adjustments	Adjusted Balance	Investment Rate	Cost of Removal	Depreciation Rate %	Investment Rate Component	Cost of Removal Component	Annualized Depreciation	FERC 403 %	Alloc of Adj to FERC 403	FERC 404 %	Alloc of Adj to FERC 404	Total FERC 403 & 404
General Plant:														
Acct. 389 Land	362,012	-	362,012	0.00%		0.00%	-	-	-					
Acct. 389 Land Rights	32,109	-	32,109	4.93%		4.93%	1,583	-	1,583	0.01%	(81)	0.00%	-	(81)
Acct. 390 Structures & Improvements	5,305,943	39,408	5,345,351	4.89%		4.89%	261,388	-	261,388	2.77%	(20,224)	0.00%	-	(20,224)
Acct. 391 Office Furniture & Equipment	1,443,680	12,493	1,456,173	4.55%		4.55%	66,256	-	66,256					
Acct. 391 Computer Equipment - PCs	641,158	5,548	646,706	20.00%		20.00%	129,341	-	129,341	8.06%	(58,866)	0.00%	-	(58,866)
Acct. 392 Transportation Equipment - Class 1	819,556	10,744	830,300	14.71%		14.71%	122,137	-	122,137					
Acct. 392 Transportation Equipment - Class 2	2,611,235	34,232	2,645,467	17.87%		17.87%	472,745	-	472,745					
Acct. 392 Transportation Equipment - Class 3	1,340,149	17,568	1,357,717	22.68%		22.68%	307,930	-	307,930					
Acct. 392 Transportation Equipment - Class 4	1,190,586	15,608	1,206,194	13.04%		13.04%	157,288	-	157,288					
Acct. 392 Transportation Equipment - Class 5	1,126,671	14,770	1,141,441	11.84%	-0.01%	11.83%	135,146	(114)	135,032	-0.24%	1,721	0.00%	-	1,721
Acct. 393 Stores Equipment	200,996	-	200,996	2.86%		2.86%	5,748	-	5,748	0.07%	(477)	0.00%	-	(477)
Acct. 394 Tools, Shop, & Garage Equip.	2,262,055	9,431	2,271,486	4.00%		4.00%	90,859	-	90,859	1.04%	(7,578)	0.00%	-	(7,578)
Acct. 395 Laboratory Equipment	600,654	186,174	786,828	11.11%		11.11%	87,417	-	87,417	0.90%	(6,586)	0.00%	-	(6,586)
Acct. 396 Power Operated Equip.	1,209,317	69,759	1,279,076	10.13%	0.36%	10.49%	129,570	4,605	134,175	1.20%	(8,775)	0.00%	-	(8,775)
Acct. 397 Communications Equip.	1,078,532	23,293	1,101,825	6.67%		6.67%	73,492	-	73,492	0.84%	(6,107)	0.00%	-	(6,107)
Acct. 398 Misc. Equipment	277,567	-	277,567	4.00%		4.00%	11,103	-	11,103	0.13%	(984)	0.00%	-	(984)
Total	20,502,220	439,028	20,941,248				2,052,003	4,491	2,056,494					-
										100.00%	(737,057)	100.00%	(3,933)	(740,990)

Pro Forma Acct. 392 Depreciation X 26.6%

Test Year Acct. 392 depreciation X 73.4%

Total Annualized Depreciation	8,888,498
Less: Vehicle Depreciation Charged to CWIP	(317,905)
Total Annualized Depreciation Expense	**8,570,593**
Test Year Recorded Depreciation Expense	9,577,868
Add: Vehicle Depreciation cleared to O&M	1,049,065
Less: System Allocations (GL Account 56000)	(1,315,350)
Test Year Depreciation Expense	**9,311,583**
Adjustment Required	**(740,990)**

Allocated Call Center and other depreciation charged to UNSG depreciation expense not applicable to UNSG plant assets.

	Acct. 403	Acct. 404	O&M Exp.	Total
Test Year Recorded	8,192,206	70,312	1,049,065	9,311,583
T.Y. As Adjusted - Annualized	8,822,119	66,379		8,888,498
Vehicle Depreciation Chgs CWIP	(1,195,132)		877,227	(317,905)
	7,626,987	66,379	877,227	8,570,593
Adjustment amount	(565,219)	(3,933)	(171,838)	(740,990)

	Total Pro Forma	Less: Griffith	Adjusted Pro Forma To Allocate
Total FERC 403	(737,057)	(6,491)	(730,566)
Total FERC 404	(3,933)	-	(3,933)
Total	(740,990)	(6,491)	(734,499)

Griffith plant is removed 100%; this removes 100% of Griffith depreciation by itself and leaves the remaining pro forma adjustment amount to be allocated to the other FERC accounts. The total pro forma is the same - only presentation changed so that Griffith was separated.

	A	B	C = A+B	D	E	F = D+E	Calc = C * D	Calc = C * E	Calc = C * F					
Description	Balance at 6/30/08	Rate Case Adjustments	Adjusted Balance	Investment Rate	Cost of Removal	Depreciation Rate %	Investment Rate Component	Cost of Removal Component	Annualized Depreciation	FERC 403 %	Alloc of Adj to FERC 403	FERC 404 %	Alloc of Adj to FERC 404	Total FERC 403 & 404

Note--for purposes of the adjustment, vehicle depreciation in O&M is treated as being in Acct. 403

**UNS GAS, INC.'S RESPONSE TO
STAFF'S FIFTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
April 16, 2009**

TF 6.54 Please list all membership payments made to industry associations (e.g., American Gas Association, Institute of Gas Technology, etc.) requested for recovery during the test year. Identify the account into which such amounts are charged.

a. State the purpose and objective of each organization listed.

b. Provide descriptive material the Company has concerning each organization's financial statements, annual budget, and activities.

c. Do any of the organizations listed engage in lobbying or advocacy activities, attempts to influence public opinion, institutional or image-building advertising? If so, list each organization which engages in such activities, and state the Company's best estimate of the portion of the organization's expenses devoted to such activities. Explain and show how such estimates were derived. State if the Company has included the portions of dues related to such activities in the test year.

RESPONSE: UNS Gas has memberships with the American Gas Association ("AGA") only.

a., b. Please see the PDF files TF 6.54 (AGA Dues) and TF 6.54 (AGA Return), Bates Nos. UNSG(0571)07347 to UNSG(0571)07356 on the enclosed CD, as responses to parts "a" and "b."

The calculation for the AGA Dues was derived by taking the 2007 & 2008 invoices dividing them by 2, getting the last half of 2007 and the first half of 2008 for the test year. This amount was reduced by the percentage of AGA dues used for marketing.

c. The AGA engages in lobbying and UNS Gas has removed the portion of its membership dues that would cover that expense by the AGA.

RESPONDENT: Gary A. Smith

WITNESS: Gary A. Smith

AMERICAN GAS ASSOCIATION
2007 BUDGET

	$ 2007 ALLOCATION	% 2007 ALLOCATION
Advertising	$345,000	1.39%
Corporate Affairs	$2,099,000	8.44%
General & Administrative	$4,665,000	18.77%
General Counsel	$1,016,000	4.09%
Industry Finance & Administrative Programs	$1,283,000	5.16%
Operations & Engineering Management	$5,993,000	24.11%
Policy, Planning & Regulatory Affairs	$3,669,000	14.76%
Public Affairs	$5,790,000	23.29%
Total Budget	$24,860,000	100.00%

Note:
Lobbying expenses, as defined under IRC Section 162, accounted for 2.12% of member dues in 2007.

AMERICAN GAS ASSOCIATION
2008 BUDGET

	$ 2008 ALLOCATION	% 2008 ALLOCATION
Advertising	$300,000	1.18%
Corporate Affairs	$2,317,000	9.14%
General & Administrative	$5,127,000	20.22%
General Counsel	$1,056,000	4.17%
Industry Finance & Administrative Programs	$852,000	3.36%
Operations & Engineering Management	$5,505,000	21.71%
Policy, Planning & Regulatory Affairs	$4,000,000	15.78%
Public Affairs	$6,195,000	24.44%
Total Budget	$25,352,000	100.00%

Note
AGA estimates that lobbying expenses, as defined under IRC Section 162, will account for 4% of member dues in 2008.

AGA Vision and Mission Statement

VISION STATEMENT

AGA's vision is to be the most effective and influential energy trade association in the United States while providing clear value to its membership.

MISSION STATEMENT

The American Gas Association represents companies delivering natural gas to customers to help meet their energy needs. AGA members are committed to delivering natural gas safely, reliably and cost-effectively in an environmentally responsible way. AGA advocates the interests of its members and their customers, and provides information and services promoting efficient demand and supply growth and operational excellence in the safe, reliable and efficient delivery of natural gas.

To further this mission, AGA:

1. Encourages, facilitates, and assists members in sharing information designed to achieve operational excellence by improving their safety, security, reliability, efficiency, and environmental and other performance metrics;

2. Assists members in managing and responding to customer energy needs, regulatory trends, natural gas markets, capital markets and emerging technologies;

3. Collects, analyzes and disseminates data on a timely basis to policy makers and the public about energy utilities and the natural gas industry;

4. Focuses on the advocacy of natural gas issues that are priorities for the membership and that are achievable in a cost-effective way;

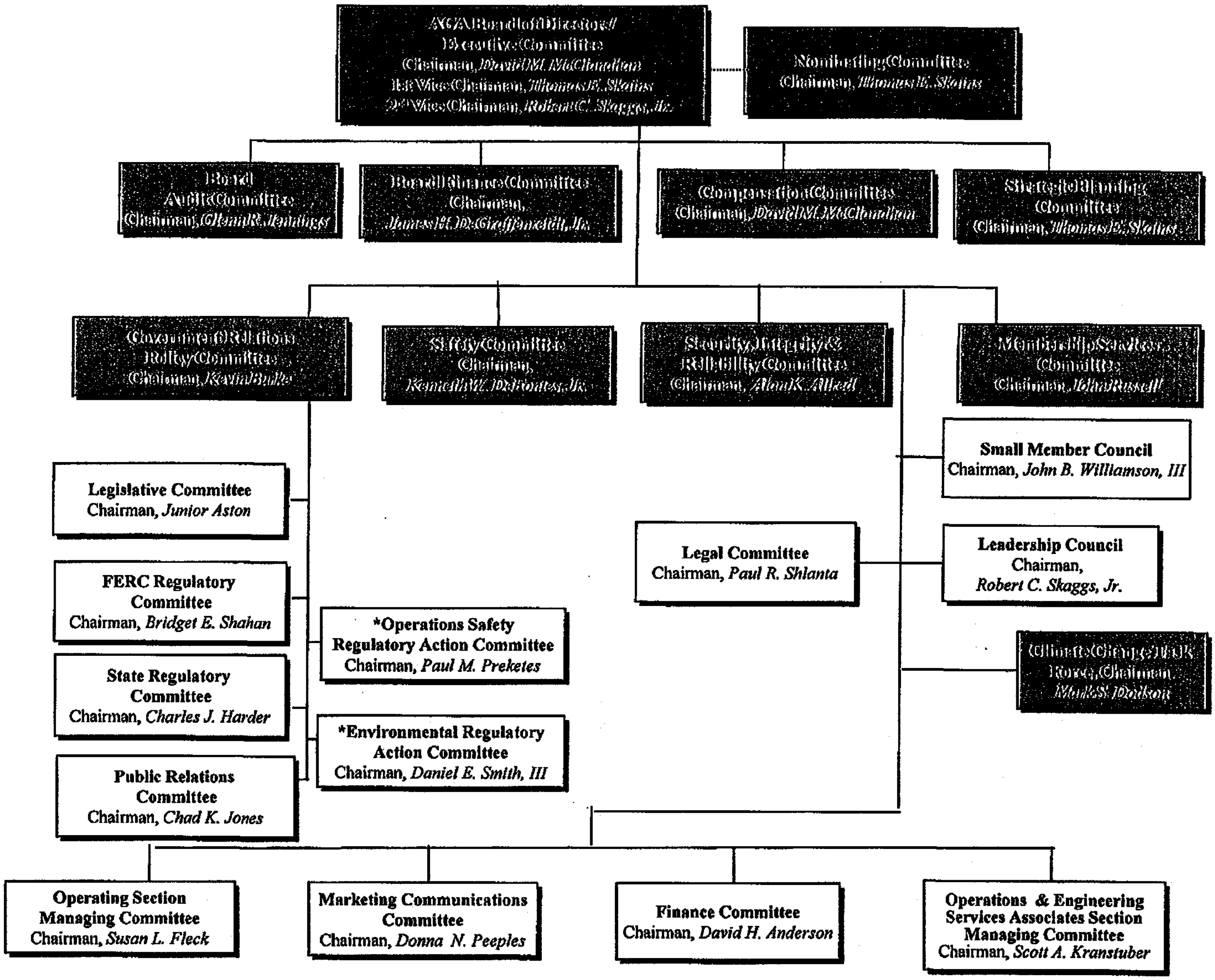
5. Serves as a voice on behalf of the energy utility industry and promotes natural gas demand growth by emphasizing before a variety of audiences the energy efficiency, environmental and other benefits of natural gas and promotes natural gas supply growth by advocating public policies favorable to increased supplies and lower prices to customers; and

6. Delivers measurable value to AGA members.

Approved September 19, 2006

AGA Committee Structure

(Shaded Committees are Board level)



Building Energy Codes & Stds.
Corrosion Control
Distribution Construction & Maintenance
Distribution & Transmission Engineering
Distribution Measurement
Environmental Matters
Executive Committee
Gas Control
Natural Gas Security
Plastic Materials
Safety & Occupational Health
Supplemental Gas
Transmission Measurement
Underground Storage
Utility & Customer Field Services

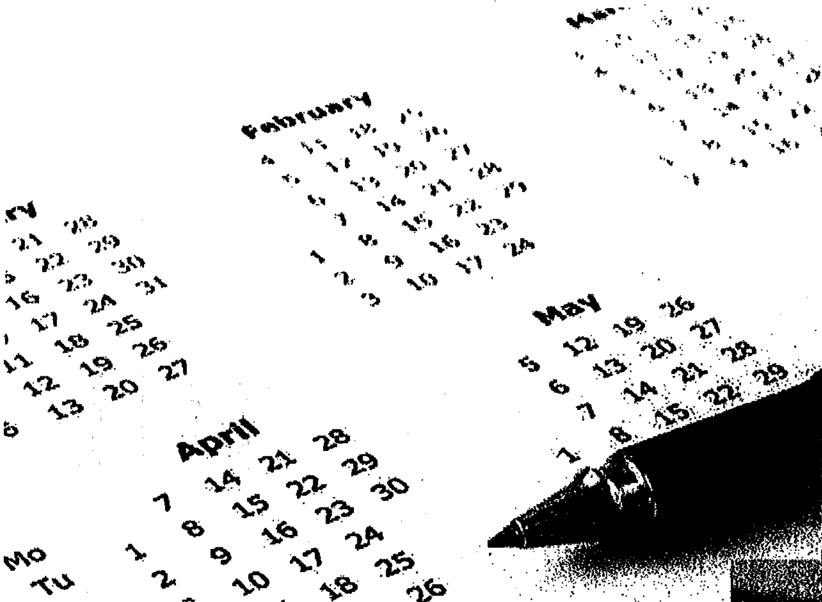
Accounting Advisory Council
Accounting Principles
Accounting Services
Compensation & Benefits
Customer Service
Human Resources Policy
Internal Audit
Labor Relations
Rate
Risk Management
Taxation
Technology Advisory Council

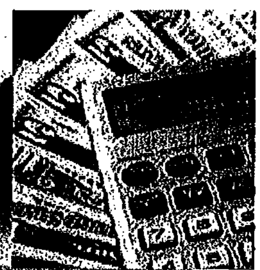
*Regulatory Action committees also report to the Operating Section Managing Committee

January 2008

The Year in Review

Team AGA tackled numerous industry issues on your behalf in 2007. Here is where we stood at year's end.





ENERGY LEGISLATION: Energy bill H.R. 6, which was signed into law Dec. 19, will not have a significant impact on natural gas utilities. We were able to remove the anti-supply provisions that were in the original House version and defeat the attempt to increase the depreciation period for natural gas distribution pipelines. On a positive note, H.R. 6 includes a provision requiring state public utility commissions to consider decoupling rate designs in rate cases. (See related story on p. 9.)

LIHEAP: Funding for the Low Income Home Energy Assistance Program for 2008 will be increased by approximately $408 million, bringing the total appropriation to just under $2.6 billion. This is the second-highest level of funding the program has ever received. (See related story on p. 32.)

CLIMATE CHANGE BILL: While the passage of comprehensive climate change legislation is not likely in 2008, AGA will continue its strong advocacy efforts. Under the direction of the board-level Climate Change Task Force, AGA has adopted climate change principles, provided written comments and met with several key members of Congress and their staffs. AGA is developing provisions that will favorably position natural gas utilities in the national debate on climate change, and the association is finalizing the study "Blueprint for a Cleaner Future: Optimizing the Use of Natural Gas to Reduce Greenhouse Emissions." AGA also is working closely with the National Association of Regulatory Utility Commissioners and other strategic partners.

DIVIDEND TAXATION: Congress will consider the extension of the 15 percent tax rate on dividends as soon as 2008. AGA is coordinating efforts with utility shareholder and other groups and conducting research to bolster its case.

SAFETY LEADERSHIP SUMMIT: AGA continued to help educate members with best practices programs, conferences, teleconferences and workshops on topics ranging from uncollectibles to leak response. At AGA's first Safety Leadership Summit, industry CEOs and senior safety personnel shared best practices in employee, customer, contractor and pipeline safety.

LIEBERMAN-WARNER CLIMATE SECURITY ACT OF 2007 (S. 2191): S. 2191 was voted out of the Senate Committee on Environment and Public Works on Dec. 5. The AGA Executive

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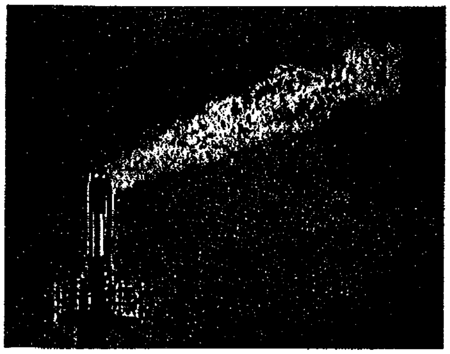
ERIN P. DOHERTY, AGA communications manager, may be reached at edoherty@aga.org.

UNSG0571/07351



Committee has met to discuss the ramifications of this legislation. The heart of the problem for local distribution companies is a provision that brings residential, commercial and small industrial natural gas customers under the cap-and-trade program and requires a 70 percent reduction in greenhouse gas emissions from natural gas by 2050.

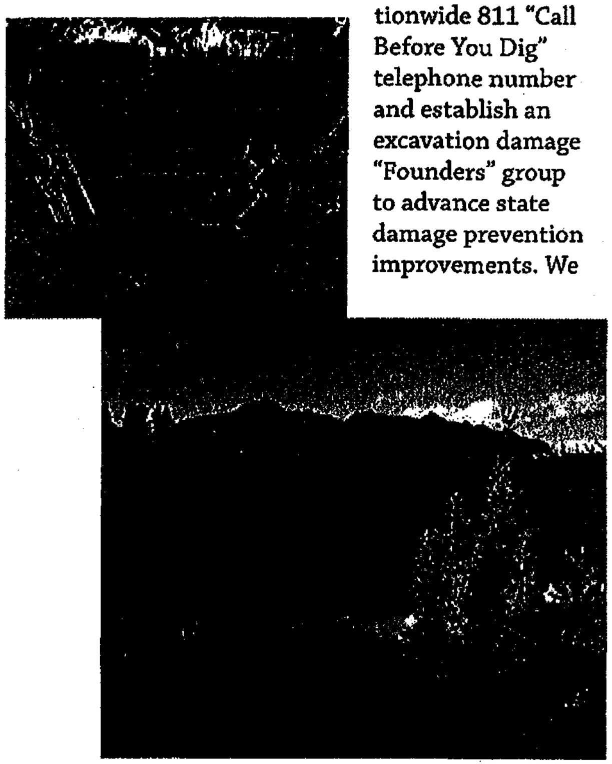
Earlier drafts of the Lieberman-Warner bill excluded natural gas utilities' customers. It is unrealistic to expect that a reduction in consumption of this magnitude can be attained by small-volume customers. Natural gas already offers more efficient and clean-burning energy than most other energy sources. Efficiency measures can further reduce natural gas consumption but not enough to meet these drastic goals. As a result, natural gas customers would be forced to compete for emission reduction credits with electric utilities and manufacturing facilities that will be turning to natural gas to help meet their own reduction goals.

OUTER CONTINENTAL SHELF ACTIVITY: AGA is a strong advocate for the National Environment and Energy Development Act (H.R. 2784), which could open additional areas of the Outer Continental Shelf. Introduced by Reps. John Peterson, R-Pa., and Neil Abercrombie, D-Hawaii, the bill has bipartisan support with 165 co-sponsors; however, it lacks support from the House leadership.

AGA provided comments encouraging expanded natural gas production for the U.S. Department of Interior's five-year Oil and Gas Leasing Plan for the OCS. The new 2007 to 2012 plan opens new areas in the Gulf of Mexico and off Alaska for natural gas exploration and production. AGA supported the Bureau of Land Management's efforts to implement provisions of the Energy Policy Act of 2005, which allowed expanded production in Colorado and Wyoming. AGA also worked with the NARUC Gas Committee to pass a resolution providing for a full cost analysis of maintaining domestic production moratoria on federal lands.

DISTRIBUTION INTEGRITY MANAGEMENT: The U.S. Department of Transportation's proposed rule for the Distribution Integrity Management Program will be delayed until March 2008. AGA believes the rule will be aligned with its goal to obtain a reasonable regulation because we have provided extensive input into the rule framework as well as information from the guidance developed by the Gas Piping Technology Committee. AGA received a favorable interpretation on the treatment of casings in the transmission integrity management rule, including a deferred assessment on cased pipe.

AGA continues to work to reduce excavation damage, helping to launch the nationwide 811 "Call Before You Dig" telephone number and establish an excavation damage "Founders" group to advance state damage prevention improvements. We have worked with the "Founders" to develop a framework for implementation of the excavation damage provisions of the Pipeline Safety Act.



ENVIRONMENTAL ISSUES: The California Climate Action Registry revised plans for its natural gas sector reporting protocol to reflect AGA's comments. We also made progress with EPA addressing the latest regional PCB concerns. In addition, EPA has agreed to negotiate an agreement with DOT to clarify which natural gas facilities will be exempt from EPA's oil spill prevention rules.

RESIDENTIAL FURNACES, BOILERS RULE: The Department of Energy issued a final rule for residential furnaces and boilers, which will ultimately result in greater energy efficiency and consumer choice. (See related story on p. 10.)

ENERGY EFFICIENCY SURVEY: AGA developed and disseminated information on the consumer response to natural gas price increases. A recent survey examined the nation's natural gas energy efficiency programs and local distribution company revenue decoupling. Forty-seven of AGA's 200 member companies, which serve more than half of U.S. residential natural gas customers, responded. At least 57 percent of U.S. natural gas residential customers are served by utilities that have an energy efficiency program.

AGA MEMBER SATISFACTION: AGA earned its highest marks to date on the annual membership satisfaction survey. Meetings and conferences met or exceeded attendance goals and yielded significant nondues revenue, which has helped fund priority initiatives, including the development of state utility shareholder organizations and AGA's "Blueprint for a Cleaner Future" study. Additionally, AGA has been awarded the opportunity to host LNG 17.

Tell Us About It!

Have a story idea or feedback on something you've read in *American Gas*? Let us know! Contact editor Stacey Bell at sbell7@tampabay.rr.com or 813/741-1772.

UNSG0571/07353

Looking Back on a Year's Worth of ROI

The monthly column reflects on key issues important to AGA members

THE CHALLENGE

PROVIDING AGA MEMBERS with quantitative and qualitative value far in excess of the dues they pay is the association's highest priority. In this regard, AGA realized two of its top advocacy goals in 2006: Congress appropriated a record $3.2 billion for the 2006 Low-Income Home Energy Assistance Program and extended until 2010 the 15 percent income tax rate on most dividend earnings and capital gains.

These advocacy activities, plus a few examples of the multitude of services AGA provided its members during the year, were highlighted in the 2006 *American Gas* "Return on Investment" columns and are summarized below.

THE RESULTS

A Leap for LIHEAP

AGA, a leading supporter of the federal Low-Income Home Energy Assistance Program (LIHEAP), used every means available to persuade Congress of the need to increase the program's fiscal 2006 funding.

The association stressed that the impact of rising energy prices is particularly harsh on low-income households and that more than 80 percent of the people eligible for LIHEAP don't receive the fuel-payment aid because the program's funding is inadequate. In response, Congress appropriated a record $3.2 billion for the 2006 LIHEAP. This compares with the $2.2 billion allotted for 2005.

AGA's successful effort means that $475 million more in LIHEAP funds were available in 2006 than in 2005 for low-income customers of member company utilities. The calculation is based on data showing that at least half of the people eligible for LIHEAP heat their homes with natural gas and AGA's utility members account for 83 percent of the gas delivered to U.S. households. (See May 2006 *American Gas.*)

A Victory for Investors

In 2003, Congress cut the federal income tax rate to 15 percent on dividends and capital gains, down from a top rate of 38.6 percent on dividend income and 20 percent on capital gains. The tax break was set to expire at the end of 2008.

AGA joined forces with the Alliance for Tax Fairness and Growth to support legislation extending the lower tax rates through 2010, which Congress passed in May. AGA's longer term goal is to see the tax cut made permanent.

Compared with the original tax rates on dividend income, the 15 percent rate reduces the federal tax bite by an estimated $750 million annually for investors holding natural gas distribution company stocks. (See July 2006 *American Gas.*)

In fulfilling its role as a professional society, AGA holds numerous conferences, workshops and exhibitions that provide forums for the exchange of ideas and information.

Addressing Natural Gas Pipe Standards and 'Rework'

A project to resolve quality-control issues related to the use of scrap resin, or "rework" material, in the manufacture of polyethylene (PE) natural gas pipe was

initiated by AGA's Plastic Materials Committee in 2002.

ASTM International's D-2513 PE gas pipe standard didn't limit the amount of rework material that may be used in the PE pipe manufacturing process. AGA believed the lack of an adequate standard could lead to mixing dirty, odd-shaped particles of rework resin with clean uniform virgin resin to produce PE pipe. This could result in imperfections or contamination within the pipe wall that create a potential initiation point for crack growth.

As a result of AGA's four-year rework project, the Plastics Pipe Institute (PPI) published "Requirements for the Use of Rework Materials in Manufacturing of Polyethylene Gas Pipe" (PPI Technical Note 30, 2006 edition). This set of guidelines states that no more than 30 percent of the resin used to make PE gas pipe shall be rework resin and includes quality-control steps designed to ensure contamination-free rework material. The 2006 PPI document will be included in the upcoming revised edition of AGA's "Plastic Pipe Manual." In addition, AGA expects the technical note will be incorporated by reference in ASTM's D-2513 standard by year's end.

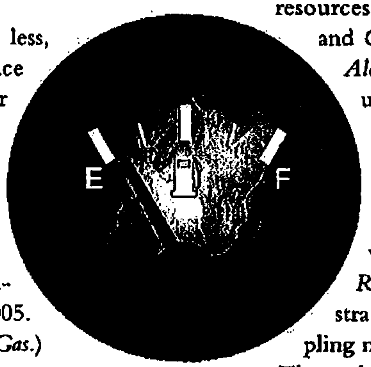
A collaborative effort of AGA,

researchers and PE pipe manufacturers, the rework project culminated in guidelines that enhance the safety and reliability of PE pipe and provide immeasurable long-term qualitative value to all of AGA's utility members. (See October 2006 *American Gas.*)

Doing More With Less

Shortly after moving its headquarters from Rosslyn, Va., to Washington, D.C., in 1999, AGA concluded it could reduce the size of the staff without hurting its effectiveness or compromising member service. Since the move, the number of employees has been reduced from 108 to 82. That left AGA with empty work stations, so the association reorganized its floor space to create a walled-off office area with a separate entrance that it sublet in 2005. In addition, AGA generates income by leasing office space to, and providing administrative services for, NGVAmerica and the Energy Solutions Center.

By doing more with less, consolidating empty space to fashion an office for sublet, and providing accommodations and services for the two gas-related entities, AGA has produced on ongoing annual savings of approximately **$322,000** since 2005. (See June 2006 *American Gas.*)



Answering Your Call for Help

Close to 300 employees of AGA member companies took advantage of the association's SOS program in 2005. Through this service, a member company gains nearly immediate access to other members by sending AGA a detailed explanation of the information it is seeking about a business function, such as accounting, human resources or operating and engineering.

In turn, AGA relays the query via e-mail to the appropriate professionals at other member companies. The person initiating the SOS information request usually receives between eight and 30 responses, often within a day or two.

For the company seeking information, an individual SOS question-answer cycle is worth an estimated $5,000 to $20,000, based on the complexity of the inquiry and what it would cost a member to do the research itself or hire a consultant to gather the information from other gas utilities. Using a figure of $12,500—the mean of the range above—the 285 queries handled through AGA's SOS service in 2005 collectively saved the companies seeking information $3.6 million. (See April 2006 *American Gas.*)

Stay Informed: State Rate Actions

Answering member requests that it give greater priority to keeping them informed about state rate actions, issues and trends, AGA revamped its rate regulation web pages and developed new online resources, including *Rate Alert* and *Gas Rate Round-Up*. The *Alert* comes out weekly unless there's no news and provides summaries of gas utility rate case decisions as well as related materials and web links. The periodic *Round-Up* discusses rate strategies, such as decoupling mechanisms.

The redesigned web pages also are a source of other types of valuable information, including data on requested and allowed returns on equity, a consultant database and survey results on test-year lengths. In addition, AGA inaugurated a program of audioconferences on rate issues, which feature two or more speakers and a question-answer period.

Those who use AGA's rate and state regulation services attest to the enormous qualitative value in having a plethora of resources just a mouse click away and hearing via audioconferences what experts have to say about the hot rate issues of the day. (See August/ September 2006 *American Gas.*)

Answering member requests that it give greater priority to keeping them informed about state rate actions, issues and trends, AGA revamped its rate regulation web pages and developed new online resources.

It Takes a Village

Utility consumer and community affairs (CCA) professionals are the first line of defense against eroding customer relations caused by higher natural gas bills.

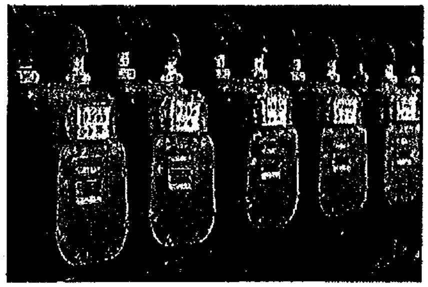
Following the dramatic escalation of natural gas prices during the 2000-01 winter, some AGA members asked the association to focus more attention on CCA activities. In reply, AGA created a CCA Task Force that is open to all who wish to participate. The group provides a formal channel for the exchange of ideas and best practices by holding monthly teleconferences during which member companies talk about their successful CCA-related programs and answer questions.

The task force members say they are very pleased to have an inexpensive means (no travel involved) of discussing CCA strategies that provide gas customers with educational and financial tools to help them manage their fuel consumption and expenses. (See March 2006 *American Gas.*)

AGA/EEI Use DataSource Benchmarking To Improve Service

AGA joined forces with the Edison Electric Institute (EEI) in the mid-1990s to launch DataSource, an extensive database of utility information related to the performance of customer service tasks.

The data come from yearly questionnaires filled out by DataSource participants and cover call centers, meter-reading, billing, collections, cash posting, revenue protection, low-income programs, fleet management, field services, customer service website/customer information system, and commercial and industrial account management. The benchmarking results are available online to DataSource participants.



The benchmarking exercise is complemented by an annual AGA/EEI DataSource Best Practices Workshop at which DataSource participants discuss the techniques they've used to improve the efficiency of various customer service functions.

DataSource is a benefit of AGA membership. The fact that there's no charge to participate in the benchmarking exercise translates into a minimum yearly savings of $10,000 for each DataSource participant. This figure is at the low end of what private-sector firms charge for benchmarking services. (See November 2006 *American Gas*.)

A Better Balance

In fulfilling its role as a professional society, AGA holds numerous conferences, workshops and exhibitions that provide forums for the exchange of ideas and information.

At a recent AGA Uncollectibles Workshop, for example, South Jersey Gas Co. told the audience about its experience with a consulting firm's automated revenue miner, which matches utility customers' inactive accounts that have balances due with these same customers' active accounts. The utility reported that over a three-month period, the consulting firm identified $804,000 in overdue balances in inactive accounts that had features, such as Social Security numbers, similar to those of current customers. The utility determined that 87 percent of those inactive-active accounts were good matches and recovered 72 percent of the overdue balances.

Myriad information and ideas are presented at AGA meetings every year. It's impossible to calculate the savings AGA member companies realize by adopting these new ideas, but if the example above is any indication of the value of AGA's role as a professional society, the savings are substantial. (See February 2006 *American Gas*.)

another photo?

THE VALUE

THE AGA SERVICES highlighted here provided the association's full, limited and international members with a return of $479 million on their 2006 dues investment of $17.8 million. The 2006 return of nearly $27 for every $1 in membership dues illustrates clearly that AGA dues are an investment, not an expense.

UNS GAS, INC.'S RESPONSE TO
RUCO'S FIRST SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
May 7, 2009

RUCO 1.48	Provide copies of the AGA dues invoices for the years 2007, 2008 and 2009.
RESPONSE:	Please see the PDF File RUCO 1.48 - AGA Invoices, Bates Nos. UNSG(0571)08823 to UNSG(0571)08825 on the enclosed CD for 2007, 2008, and 2009 AGA Invoices.
RESPONDENT:	Mina Briggs
WITNESS:	Gary Smith

02/26/2007 11:45 5208843606 CR PAGE 03

PO# 11790-1

AGA
American Gas Association

Post Office Box 79226
Baltimore, Maryland 21279-0226
Telephone (202)824-7256
Fax (202)824-9156

UniSource Energy Corporation

2007 DUES

Year ending December 31, 2007

Full Member Company X   Limited Member Company ____

A.G.A. Dues Rules are attached. Dues are based upon the following operating income information ($000):

2003 4,128   2004 15,658   2005 14,000   Average 11,262

1-17-07

YOUR 2006 DUES WERE .... **$ 43,486**

YOUR 2007 DUES ARE .... **$ 45,508**

UNS G
mB

2007 Payment Schedule

____ Full amount enclosed   ____ Semi-annually (Jan.1, July 1)

____ Quarterly (Jan.1, Apr.1, July 1, Oct.1)   ____ Other (Please state)

return ck to Soltz or Garcia Transfer

Please return this completed form to the A.G.A. Treasurer at the above address. Payments may also be directed to the address noted above.

Invoice to: ....   Approved: ....

....   Title ....

....   Date: ....

....

notify Soltz@tep.com

Phone: ( ) .... - ....   Fax ( ) .... - ....

IMPORTANT IRS REQUIRED NOTICE

Federal regulations require us to advise you that contributions or gifts to the American Gas Association are not deductible as charitable contributions for federal income tax purposes. Dues payments are usually deductible by members as an ordinary and necessary business expense. The American Gas Association expects that a portion of your dues may be used to influence legislation. **The Association will pay directly the federal tax that is due on lobbying activities.**

Dues include a one-year subscription to *American Gas*, the normal subscription rate for which is $59.00 per year for U.S. and Canadian subscribers and $110.00 per year for international subscribers.

PAGE 3/3 * RCVD AT 2/26/2007 11:49:25 AM [US Mountain Standard Time] * SVR:TEPFAX/10 * DNIS:429 * CSID:5208843606 * DURATION (mm-ss):01-16

AGA
American Gas Association

Post Office Box 79226
Baltimore, Maryland 21279-0226
Telephone (202)824-7256
Fax (202)824-9156

UniSource Energy Corporation

PO# 11790-2

2008 DUES

Year ending December 31, 2008

Full Member Company X Limited Member Company ____

A.G.A. Dues Rules are attached. Dues are based upon the following operating income information ($000):

2004 15,658 2005 14,000 2006 14,000 Average 14,553

YOUR 2007 DUES WERE .... $ 45,508

YOUR 2008 DUES ARE .... $ 47,879

UNSG
MB
rec 1-8-08

2008 Payment Schedule

______ Full amount enclosed ______ Semi-annually (Jan.1, July 1)

______ Quarterly (Jan.1, Apr.1, July 1, Oct.1) ______ Other (Please state) on notification return ck to Foltz UE102

Please return this completed form to the A.G.A. Treasurer at the above address. Payments may also be directed to the address noted above.

Invoice to: .... Approved: ....

.... Title ....

.... Date: ....

....

Phone: ( ) .... - .... Fax ( ) .... - ....

IMPORTANT IRS REQUIRED NOTICE

Federal regulations require us to advise you that contributions or gifts to the American Gas Association are not deductible as charitable contributions for federal income tax purposes. Dues payments are usually deductible by members as an ordinary and necessary business expense. The American Gas Association expects that a portion of your dues may be used to influence legislation. **It is estimated that approximately four percent of your dues may be non-deductible as an ordinary and necessary business expense.** The Association will inform you if the actual non-deductible amount materially exceeds this estimate.

Dues include a one-year subscription to ***American Gas***, the normal subscription rate for which is $59.00 per year for U.S. and Canadian subscribers and $110.00 per year for international subscribers.

01/14/2009 08:58 5208843606 CR

PO# 11790-3

AGA
American Gas Association

Post Office Box 79226
Baltimore, Maryland 21279-0226
Telephone (202)824-7256
Fax (202)824-9156

UniSource Energy Corporation

Ben - please process PO to pay immediately. Thanks S 1-13-08

UNSGmb

2009 DUES

Year ending December 31, 2009

Full Member Company X   Limited Member Company ___

A.G.A. Dues Rules are attached. Dues are based upon the following operating income information ($000):

2005 14,000   2006 14,000   2007 13,000   Average 13,667

YOUR 2008 DUES WERE .... $ 47,879

YOUR 2009 DUES ARE .... $ 51,901

2009 Payment Schedule

✓ Full amount enclosed   ___ Semi-annually (Jan.1, July 1)

___ Quarterly (Jan.1, Apr.1, July 1, Oct.1)   ___ Other (Please state)

Please return this completed form to the A.G.A. Treasurer at the above address. Payments may also be directed to the address noted above.

Invoice to: ....   Approved: ....

....   Title ....

....   Date: ....

....

Phone: ( ) .... - ....   Fax ( ) .... - ....

IMPORTANT IRS REQUIRED NOTICE

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Dues include a one-year subscription to ***American Gas***, the normal subscription rate for which is $59.00 per year for U.S. and Canadian subscribers and $110.00 per year for international subscribers.

01/10/2008 10:16 5208843606 CR PAGE 01

AGA
American Gas Association

Post Office Box 79226
Baltimore, Maryland 21279-0226
Telephone (202)824-7256
Fax (202)824-9156

UniSource Energy Corporation

PO# 11790-2

Remove 4% for lobbying

2008 DUES

Year ending December 31, 2008

Full Member Company X Limited Member Company ___

A.G.A. Dues Rules are attached. Dues are based upon the following operating income information ($000):

2004 15,658 2005 14,000 2006 14,000 Average 14,553

YOUR 2007 DUES WERE .... **$ 45,508**

YOUR 2008 DUES ARE .... **$ 47,879**

UNSG MB 1-8-08

2008 Payment Schedule

___ Full amount enclosed ___ Semi-annually (Jan.1, July 1)

___ Quarterly (Jan.1, Apr.1, July 1, Oct.1) ___ Other (Please state)

req'd on notification return ck to Foltz UE102

Please return this completed form to the A.G.A. Treasurer at the above address. Payments may also be directed to the address noted above.

Invoice to: .... Approved: ....

.... Title ....

.... Date: ....

....

Phone: ( )........ - .... Fax ( )........ - ....

IMPORTANT IRS REQUIRED NOTICE

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Dues include a one-year subscription to ***American Gas***, the normal subscription rate for which is $59.00 per year for U.S. and Canadian subscribers and $110.00 per year for international subscribers.

PAGE 1/1 * RCVD AT 1/10/2008 10:24:44 AM [US Mountain Standard Time] * SVR:TEPFAX/0 * DNIS:429 * CSID:5208843606 * DURATION (mm-ss):01-02

24

UNS GAS, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2008

ADJUSTMENT NAME:	Normalize Outside Legal Expense
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	September 30, 2008
PREPARED BY:	Mina Briggs & Janet Zaidenberg-Schrum JZS 9/30/08
CHECKED BY:	Mina Briggs & Janet Zaidenberg-Schrum MB 9/30/08
REVIEWED BY:	Dallas Dukes DD

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
		✓	
923	Outside Services Employed 1a	$305,984	
	ENTRY TOTAL	**$305,984**	**$0**
	NET ENTRY		**($305,984)**

Reason for Adjustment

To normalize outside legal expense for the test year. ✓

9/30/2008 12:09 PM

UNS Gas, Inc.
Legal Expenses - 3 Year Average
Test Year Ended June 30, 2008

Task	Task Description	Test Year	2007	2006	2005	
GTP0923	Admin & General Salaries	2.3A $5,778.57	3.3A $13,010.60	4.2A $12,460.02	5.2A $28,830.40	
GTPA160	Legal: El Paso Gas Allocation	$99,887.50	$196,203.43	$395,246.86	$361,232.89	
GTPD160	Legal: PGA Application	$0.00	$3.00	$27,722.06	$68,901.93	
GTPF160	Legal: UNSG Santa Cruz Gomez v. Cabrera, et al.	$14,536.76	$52,918.35	$18,927.03	$690.00	
GTPH160	Legal: Allstate v UES-Gas	$602.42	$602.42	$0.00	$0.00	
UNG06RC	UNS Gas Rate Case-2006	$310,060.91	$307,303.51 c	$0.00	$0.00	
	All other - JE, Accruals, Reversals	($36,353.00)	($21,041.50)	($15,815.35)	$28,724.86	
		$394,513.16	$548,999.81	$438,540.62	$488,380.08	$1,475,920.51 b

3 Year Average	$491,973.50	Including the Rate Case Exp. Write-off

Removed through Proforma Adjustments		
DSM Proforma Adjustment	$897.00	2.3B
Misc. Proforma Adjustment - 2006 Rate Case Exp	$310,060.91	
	$310,957.91	
Amount Left In Test Year for Legal for Legal	**$83,555.25**	2.3C

3 Year Average - Expense for Test Year ①	$389,539.00	Excluding the Rate Case Exp. Write-off
Test Yr. Level After Other Adjustments	($83,555.25)	2.3C
Adjustment for Recurring Legal Expense	**$305,983.75**	a

$① = \frac{b - c}{3}$

$1,475,920.51
(307,303.51)
$1,168,617.00
÷ 3
$389,539

UNS GAS - TEST YEAR LEGAL EXPENSES

Company:032
Expenditure Type:152 - Legal Expense
BY FERC

GL Period	FERC	Acct	Pa Task Number	Pa Expenditure Comment	Gl JE Name	DR	CR	Net Amount	Invoice Number	Vendor Name	
MAR-08	0908	52010	GCIFDSM		Purchase Invoices USD	224.25		224.25	35663	ROSHKA DEWULF & PATTEN PLC	Removed with DSM Proforma Adjustment
MAR-08	0908	52010	GEHHDSM		Purchase Invoices USD	224.25		224.25	35663	ROSHKA DEWULF & PATTEN PLC	
MAR-08	0908	52010	GESHDSM		Purchase Invoices USD	224.25		224.25	35663	ROSHKA DEWULF & PATTEN PLC	
MAR-08	0908	52010	GWEADSM		Purchase Invoices USD	$224.25		$224.25	35663	ROSHKA DEWULF & PATTEN PLC	
	Sum					$897.00		$897.00			
AUG-07	0923	52010	GTP0923		Purchase Invoices USD	$853.20		$853.20	34588	ROSHKA DEWULF & PATTEN PLC	
OCT-07	0923	52010	GTP0923		Purchase Invoices USD	$10.80		$10.80	34924	ROSHKA DEWULF & PATTEN PLC	
NOV-07	0923	52010	GTP0923		Purchase Invoices USD	$62.00		$62.00	35078	ROSHKA DEWULF & PATTEN PLC	
NOV-07	0923	52010	GTP0923		Purchase Invoices USD	$1,644.85		$1,644.85	35077	ROSHKA DEWULF & PATTEN PLC	
DEC-07	0923	52010	GTP0923		Purchase Invoices USD	$1,787.02		$1,787.02	35121	ROSHKA DEWULF & PATTEN PLC	
DEC-07	0923	52010	GTP0923		Purchase Invoices USD	$8.00		$8.00	35114	ROSHKA DEWULF & PATTEN PLC	
JAN-08	0923	52010	GTP0923		Purchase Invoices USD	321.40		321.40	35405	ROSHKA DEWULF & PATTEN PLC	
MAR-08	0923	52010	GTP0923		Purchase Invoices USD	58.50		$58.50	35663	ROSHKA DEWULF & PATTEN PLC	
MAR-08	0923	52010	GTP0923		Purchase Invoices USD	1,152.80		$1,152.80	35536	ROSHKA DEWULF & PATTEN PLC	
MAY-08	0923	52010	GTP0923		Purchase Invoices USD	30.00		$30.00	043008 11744572	ROSHKA DEWULF & PATTEN PLC	
AUG-07	0923	52010	GTP0923	LA POSADA HOTEL			150.00	($150.00)			
SEP-07	0923	52010	GTPA160		Purchase Invoices USD	16,761.50		$16,761.50	645312	LOCKE LIDDELL & SAPP LLP	
SEP-07	0923	52010	GTPA160		Purchase Invoices USD	9,350.00		9,350.00	642031	LOCKE LIDDELL & SAPP LLP	
SEP-07	0923	52010	GTPA160		Purchase Invoices USD	4,502.50		4,502.50	625723	LOCKE LIDDELL & SAPP LLP	
OCT-07	0923	52010	GTPA160		Purchase Invoices USD	2,515.00		2,515.00	648068	LOCKE LIDDELL & SAPP LLP	
OCT-07	0923	52010	GTPA160		Purchase Invoices USD	30,484.35		30,484.35	635624	LOCKE LIDDELL & SAPP LLP	
NOV-07	0923	52010	GTPA160		Purchase Invoices USD	3,045.00		3,045.00	652514	LOCKE LIDDELL & SAPP LLP	
DEC-07	0923	52010	GTPA160		Purchase Invoices USD	447.69		447.69	660040	LOCKE LIDDELL & SAPP LLP	
DEC-07	0923	52010	GTPA160		Purchase Invoices USD	27,971.50		27,971.50	656799	LOCKE LIDDELL & SAPP LLP	
FEB-08	0923	52010	GTPA160		Purchase Invoices USD	2,712.50		2,712.50	663814	LOCKE LIDDELL & SAPP LLP	
MAR-08	0923	52010	GTPA160		Purchase Invoices USD	32.46		32.46	666730A	LOCKE LIDDELL & SAPP LLP	
MAR-08	0923	52010	GTPA160		Purchase Invoices USD	1,032.50		1,032.50	666730	LOCKE LIDDELL & SAPP LLP	
JUN-08	0923	52010	GTPA160		Purchase Invoices USD	1,032.50		1,032.50	674225	LOCKE LIDDELL & SAPP LLP	
AUG-07	0923	52010	GTPF160		Purchase Invoices USD	1,077.80		1,077.80	40642001008O607	BEALE MICHEAELS & SLACK PC	
AUG-07	0923	52010	GTPF160		Purchase Invoices USD	4,808.84		4,808.84	40642001007 2507	BEALE MICHEAELS & SLACK PC	
AUG-07	0923	52010	GTPF160		Purchase Invoices USD	7,728.27		7,728.27	062707 40642-0010	BEALE MICHEAELS & SLACK PC	
OCT-07	0923	52010	GTPF160		Purchase Invoices USD	161.85		161.85	12105	INVESTIGATIVE RESEARCH INC	
OCT-07	0923	52010	GTPF160		Purchase Invoices USD	137.50		137.50	100507 40642	BEALE MICHEAELS & SLACK PC	
NOV-07	0923	52010	GTPF160		Purchase Invoices USD	500.00		500.00	40642001011307	BEALE MICHEAELS & SLACK PC	
JAN-08	0923	52010	GTPF160		Purchase Invoices USD	60.00		60.00	TEP2008-1	LESHER & CORRADINI	
MAR-08	0923	52010	GTPF160		Purchase Invoices USD	62.50		62.50	02208 6612203	BEALE MICHEAELS & SLACK PC	
AUG-07	0923	52010	GTPH160		Purchase Invoices USD	142.60		142.60	51269	PRODOX LLC	
AUG-07	0923	52010	GTPH160		Purchase Invoices USD	126.18		126.18	51157	PRODOX LLC	
SEP-07	0923	52010	GTPH160		Purchase Invoices USD	92.85		92.85	52620	PRODOX LLC	
DEC-07	0923	52010	GTPH160		Purchase Invoices USD	90.79		90.79	TEP2012-7	LESHER & CORRADINI	
JUL-07	0923	52010	GTPH160	LA POSADA HOTEL		150.00		150.00			
DEC-07	0923	52010	UNG06RC		Purchase Invoices USD	15,661.35		15,661.35	35117	ROSHKA DEWULF & PATTEN PLC	
JAN-08	0923	52010	UNG06RC		Purchase Invoices USD	1,369.40		1,369.40	35402	ROSHKA DEWULF & PATTEN PLC	
MAR-08	0923	52010	UNG06RC		Purchase Invoices USD	1,150.50		1,150.50	35663	ROSHKA DEWULF & PATTEN PLC	
MAY-08	0923	52010	UNG06RC		Purchase Invoices USD	237.50		237.50	043008 11744572	ROSHKA DEWULF & PATTEN PLC	
MAR-08	0923	52010			Accrual USD APR-08	0.53		0.53			
JUL-07	0923	52010			Accrual USD AUG-07	0.53		0.53			
NOV-07	0923	52010			Accrual USD DEC-07	0.53		0.53			
JAN-08	0923	52010			Accrual USD FEB-08	0.53		0.53			
JUN-08	0923	52010			Accrual USD JUL-08	0.53		0.53			
MAY-08	0923	52010			Accrual USD JUN-08	0.53		0.53			

9/30/2008 12:08 PM

UNSG0571/02565

2.1

UNS GAS - TEST YEAR LEGAL EXPENSES

Company:032
Expenditure Type:152 - Legal Expense
BY FERC

GL Period	FERC	Acct	Pa Task Number	Pa Expenditure Comment	Gl JE Name	DR	CR	Net Amount	Invoice Number	Vendor Name
FEB-08	0923	52010			Accrual USD MAR-08	1,065.49		1,065.49		
APR-08	0923	52010			Accrual USD MAY-08	0.53		0.53		
OCT-07	0923	52010			Accrual USD NOV-07	0.53		0.53		
SEP-07	0923	52010			Accrual USD OCT-07	0.53		0.53		
AUG-07	0923	52010			Accrual USD SEP-07	0.53		0.53		
SEP-07	0923	52010			J341 - Legal Accrual Accrual USD		6,250.00	(6,250.00)		
DEC-07	0923	52010			J341 AP Legal Accrual Adjustment	29,000.00		29,000.00		
FEB-08	0923	52010			J341 AP Legal Accrual Adjustment	28,000.00		28,000.00		
MAR-08	0923	52010			J356 - Reverses "J341 AP Legal Accrual Adjustment USD"02-APR-08		28,000.00	(28,000.00)		
FEB-08	0923	52010			J356 - Reverses "J341 AP Legal Accrual Adjustment USD"04-MAR-08		29,000.00	(29,000.00)		
JUL-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 01-AUG-07 13:44:15	0.00		0.00		
DEC-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 03-JAN-08 08:07:01	0.00		0.00		
FEB-08	0923	52010			J817 UES UBOC Debt Cost Amtz: 03-MAR-08 10:58:16	0.00		0.00		
JAN-08	0923	52010			J817 UES UBOC Debt Cost Amtz: 08-FEB-08 07:53:43	0.00		0.00		
SEP-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 28-SEP-07 08:12:09	0.00		0.00		
AUG-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 29-AUG-07 08:38:45	0.00		0.00		
APR-08	0923	52010			J817 UES UBOC Debt Cost Amtz: 30-APR-08 08:07:32	0.00		0.00		
JUN-08	0923	52010			J817 UES UBOC Debt Cost Amtz: 30-JUN-08 07:59:47	0.00		0.00		
MAY-08	0923	52010			J817 UES UBOC Debt Cost Amtz: 30-MAY-08 11:26:40	0.00		0.00		
NOV-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 30-NOV-07 08:26:08	0.00		0.00		
OCT-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 30-OCT-07 14:27:59	0.00		0.00		
MAR-08	0923	52010			J817 UES UBOC Debt Cost Amtz: 31-MAR-08 08:04:51	0.00		0.00		
NOV-07	0923	52010	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
OCT-07	0923	52010	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
SEP-07	0923	52010	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
DEC-07	0923	52010			J975 Reverse 3rd Quarter Adjustment		31,000.00	(31,000.00)		
APR-08	0923	52010			Reverses "Accrual USD APR-08"22-APR-08 14:21:19		0.53	(0.53)		
AUG-07	0923	52010			Reverses "Accrual USD AUG-07"30-AUG-07 10:55:42		0.53	(0.53)		
DEC-07	0923	52010			Reverses "Accrual USD DEC-07"31-DEC-07 13:45:17		0.53	(0.53)		
FEB-08	0923	52010			Reverses "Accrual USD FEB-08"04-		0.53	(0.53)		
JUL-07	0923	52010			Reverses "Accrual USD JUL-07"26-		0.53	(0.53)		
JUN-08	0923	52010			Reverses "Accrual USD JUN-08"25-		0.53	(0.53)		
MAR-08	0923	52010			Reverses "Accrual USD MAR-08"26-MAR-08 13:15:52		1,065.49	(1,065.49)		

UNS GAS - TEST YEAR LEGAL EXPENSES

Company:032
Expenditure Type:152 - Legal Expense
BY FERC

GL Period	FERC	Acct	Pa Task Number	Pa Expenditure Comment	Gl JE Name	DR	CR	Net Amount	Invoice Number	Vendor Name
MAY-08	0923	52010			Reverses "Accrual USD MAY-08"27-MAY-08 15:28:51		0.53	(0.53)		
NOV-07	0923	52010			Reverses "Accrual USD NOV-07"27-NOV-07 13:42:47		0.53	(0.53)		
OCT-07	0923	52010			Reverses "Accrual USD OCT-07"26-		0.53	(0.53)		
SEP-07	0923	52010			Reverses "Accrual USD SEP-07"20-SEP-07 10:41:01		0.53	(0.53)		
	Sum					489,086.95	95,470.79	393,616.16		
Total						489,983.95	95,470.79	394,513.16		

Task	Task Description		
GTP0923	Admin & General Salaries	$5,778.57	A
GTPA160	Legal: El Paso Gas Allocation	$99,887.50	
GTPF160	Legal: UNSG Santa Cruz Gomez v. Cabrera, et al.	$14,536.76	
GTPH160	Legal: Allstate v UES-Gas	$602.42	
UNG06RC	UNS Gas Rate Case 2006	$310,060.91	
	All other - JE, Accruals, Reversals	($36,353.00)	
		$394,513.16	
	Removed through Proforma		
	DSM Proforma Adjustment	$897.00	B
	Misc. Proforma Adjustment - 2006	$310,060.91	
		$310,957.91	
	Amount Left in Test Year for Legal	**$83,555.25**	C

9/30/2008 12:08 PM

23

UNSG0571/02567

UNS Gas Legal Expenses - 2007

Company:032
Expenditure Type:152
BY FERC

GL Period	FERC	Acct	Pa Task Number	Pa Expenditure Comment	Gl JE Name	DR	CR	Net Amount	Invoice Number	Vendor Name
JAN-07	0923	52010	GTP0923		Purchase Invoices USD	413.00		413.00	33616	ROSHKA DEWULF & PATTEN PLC
JAN-07	0923	52010	GTP0923		Purchase Invoices USD	2,508.00		2,508.00	6957465	THELEN REID BROWN RAYSMAN & STEINER LLP
APR-07	0923	52010	GTP0923		Purchase Invoices USD	1,778.32		1,778.32	7300913	THELEN REID BROWN RAYSMAN & STEINER LLP
APR-07	0923	52010	GTP0923		Purchase Invoices USD	$1,518.75		$1,518.75	6964015	THELEN REID BROWN RAYSMAN & STEINER LLP
APR-07	0923	52010	GTP0923		Purchase Invoices USD	$560.00		$560.00	34026	ROSHKA DEWULF & PATTEN PLC
APR-07	0923	52010	GTP0923		Purchase Invoices USD	$53.06		$53.06	801752	LEWIS AND ROCA LLP
MAY-07	0923	52010	GTP0923		Purchase Invoices USD	$1,783.60		$1,783.60	34163	ROSHKA DEWULF & PATTEN PLC
JUN-07	0923	52010	GTP0923		Purchase Invoices USD	$180.00		$180.00	0507	MELISSA PIGNATELLI O BRIEN
AUG-07	0923	52010	GTP0923		Purchase Invoices USD	$853.20		$853.20	34588	ROSHKA DEWULF & PATTEN PLC
AUG-07	0923	52010	GTP0923	LA POSADA HOTEL			$150.00	($150.00)		
OCT-07	0923	52010	GTP0923		Purchase Invoices USD	$10.80		$10.80	34924	ROSHKA DEWULF & PATTEN PLC
NOV-07	0923	52010	GTP0923		Purchase Invoices USD	62.00		62.00	35078	ROSHKA DEWULF & PATTEN PLC
NOV-07	0923	52010	GTP0923		Purchase Invoices USD	1,644.85		$1,644.85	35077	ROSHKA DEWULF & PATTEN PLC
DEC-07	0923	52010	GTP0923		Purchase Invoices USD	8.00		$8.00	35114	ROSHKA DEWULF & PATTEN PLC
DEC-07	0923	52010	GTP0923		Purchase Invoices USD	1,787.02		$1,787.02	35121	ROSHKA DEWULF & PATTEN PLC
JAN-07	0923	52010	GTPA160		Purchase Invoices USD	37,955.10		$37,955.10	615738	LOCKE LIDDELL & SAPP LLP
FEB-07	0923	52010	GTPA160		Purchase Invoices USD	22,095.10		$22,095.10	618248	LOCKE LIDDELL & SAPP LLP
MAR-07	0923	52010	GTPA160		Purchase Invoices USD	22,950.69		22,950.69	622206	LOCKE LIDDELL & SAPP LLP
MAY-07	0923	52010	GTPA160		Purchase Invoices USD	12,760.00		12,760.00	629548	LOCKE LIDDELL & SAPP LLP
JUN-07	0923	52010	GTPA160		Purchase Invoices USD	5,365.00		5,365.00	633230	LOCKE LIDDELL & SAPP LLP
SEP-07	0923	52010	GTPA160		Purchase Invoices USD	16,761.50		16,761.50	645312	LOCKE LIDDELL & SAPP LLP
SEP-07	0923	52010	GTPA160		Purchase Invoices USD	9,350.00		9,350.00	642031	LOCKE LIDDELL & SAPP LLP
SEP-07	0923	52010	GTPA160		Purchase Invoices USD	4,502.50		4,502.50	625723	LOCKE LIDDELL & SAPP LLP
OCT-07	0923	52010	GTPA160		Purchase Invoices USD	2,515.00		2,515.00	648068	LOCKE LIDDELL & SAPP LLP
OCT-07	0923	52010	GTPA160		Purchase Invoices USD	30,484.35		30,484.35	635624	LOCKE LIDDELL & SAPP LLP
NOV-07	0923	52010	GTPA160		Purchase Invoices USD	3,045.00		3,045.00	652514	LOCKE LIDDELL & SAPP LLP
DEC-07	0923	52010	GTPA160		Purchase Invoices USD	27,971.50		27,971.50	656799	LOCKE LIDDELL & SAPP LLP
DEC-07	0923	52010	GTPA160		Purchase Invoices USD	447.69		447.69	660040	LOCKE LIDDELL & SAPP LLP
JAN-07	0923	52010	GTPD160		Purchase Invoices USD	3.00		3.00	33616	ROSHKA DEWULF & PATTEN PLC
JAN-07	0923	52010	GTPF160		Purchase Invoices USD	837.50		837.50	121106 40642-0010	BEALE MICHEAELS & SLACK PC
JAN-07	0923	52010	GTPF160		Purchase Invoices USD	3,810.81		3,810.81	406420010010407	BEALE MICHEAELS & SLACK PC
JAN-07	0923	52010	GTPF160		Purchase Invoices USD	143.90		143.90	11732	INVESTIGATIVE RESEARCH INC
FEB-07	0923	52010	GTPF160		Purchase Invoices USD	3,245.04		3,245.04	020707 324504	BEALE MICHEAELS & SLACK PC
MAR-07	0923	52010	GTPF160		Purchase Invoices USD	320.15		320.15	7526	BOULEY & SCHIPPERS
MAR-07	0923	52010	GTPF160		Purchase Invoices USD	600.00		600.00	030707 60000	MIRNA GALLEGO
APR-07	0923	52010	GTPF160		Purchase Invoices USD	377.00		377.00	032707 37700	MIRNA GALLEGO
APR-07	0923	52010	GTPF160		Purchase Invoices USD	300.00		300.00	032707 30000	MIRNA GALLEGO
APR-07	0923	52010	GTPF160		Purchase Invoices USD	821.85		821.85	7654	BOULEY & SCHIPPERS
APR-07	0923	52010	GTPF160		Purchase Invoices USD	837.00		837.00	7605	BOULEY & SCHIPPERS
APR-07	0923	52010	GTPF160		Purchase Invoices USD	13,402.91		13,402.91	041907 40642-0010	BEALE MICHEAELS & SLACK PC
APR-07	0923	52010	GTPF160		Purchase Invoices USD	8,200.00		8,200.00	030607 40642-0010	BEALE MICHEAELS & SLACK PC
MAY-07	0923	52010	GTPF160		Purchase Invoices USD	4,209.60		4,209.60	406420010050407	BEALE MICHEAELS & SLACK PC
JUN-07	0923	52010	GTPF160		Purchase Invoices USD	225.00		225.00	2007-1261	ISABEL FIERROS
JUN-07	0923	52010	GTPF160		Purchase Invoices USD	0.00		0.00	2007/1261CANCELLE	ISABEL FIERROS
JUN-07	0923	52010	GTPF160		Purchase Invoices USD	1,173.33		1,173.33	63	THOMAS A ZLAKET PLLC
JUN-07	0923	52010	GTPF160		Purchase Invoices USD	0.00		0.00	63 cancelled	THOMAS A ZLAKET PLLC
AUG-07	0923	52010	GTPF160		Purchase Invoices USD	7,728.27		7,728.27	062707 40642-0010	BEALE MICHEAELS & SLACK PC
AUG-07	0923	52010	GTPF160		Purchase Invoices USD	4,808.84		4,808.84	406420010072507	BEALE MICHEAELS & SLACK PC
AUG-07	0923	52010	GTPF160		Purchase Invoices USD	1,077.80		1,077.80	406420010080607	BEALE MICHEAELS & SLACK PC
OCT-07	0923	52010	GTPF160		Purchase Invoices USD	161.85		161.85	12105	INVESTIGATIVE RESEARCH INC
OCT-07	0923	52010	GTPF160		Purchase Invoices USD	137.50		137.50	100507 40642	BEALE MICHEAELS & SLACK PC

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UNS Gas Legal Expenses - 2007
Company:032
Expenditure Type:152
BY FERC

GL Period	FERC	Acct	Pa Task Number	Pa Expenditure Comment	Gl JE Name	DR	CR	Net Amount	Invoice Number	Vendor Name
NOV-07	0923	52010	GTPF160		Purchase Invoices USD	500.00		500.00	406420010111307	BEALE MICHEAELS & SLACK PC
JUL-07	0923	52010	GTPH160	LA POSADA HOTEL		150.00		150.00		
AUG-07	0923	52010	GTPH160		Purchase Invoices USD	126.18		126.18	51157	PRODOX LLC
AUG-07	0923	52010	GTPH160		Purchase Invoices USD	142.60		142.60	51269	PRODOX LLC
SEP-07	0923	52010	GTPH160		Purchase Invoices USD	92.85		92.85	52620	PRODOX LLC
DEC-07	0923	52010	GTPH160		Purchase Invoices USD	90.79		90.79	TEP2012-7	LESHER & CORRADINI
DEC-07	0923	52010	UNG06RC		Purchase Invoices USD	15,661.35		15,661.35	35117	ROSHKA DEWULF & PATTEN PLC
MAR-07	0923	52010			Accrual USD APR-07	0.53		0.53		
JUL-07	0923	52010			Accrual USD AUG-07	0.53		0.53		
NOV-07	0923	52010			Accrual USD DEC-07	0.53		0.53		
JAN-07	0923	52010			Accrual USD FEB-07	0.53		0.53		
JUN-07	0923	52010			Accrual USD JUL-07	0.53		0.53		
MAY-07	0923	52010			Accrual USD JUN-07	0.53		0.53		
FEB-07	0923	52010			Accrual USD MAR-07	0.53		0.53		
APR-07	0923	52010			Accrual USD MAY-07	0.53		0.53		
OCT-07	0923	52010			Accrual USD NOV-07	0.53		0.53		
SEP-07	0923	52010			Accrual USD OCT-07	0.53		0.53		
AUG-07	0923	52010			Accrual USD SEP-07	0.53		0.53		
MAR-07	0923	52010			J341 - Legal Accrual Accrual USD		13,000.00	(13,000.00)		
MAR-07	0923	52010			J341 - Legal Accrual Accrual USD	54,000.00		54,000.00		
JUN-07	0923	52010			J341 - Legal Accrual Accrual USD		50,350.00	(50,350.00)		
SEP-07	0923	52010			J341 - Legal Accrual Accrual USD		6,250.00	(6,250.00)		
DEC-07	0923	52010			J341 AP Legal Accrual Adjustment USD	29,000.00		29,000.00		
JUL-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 01-AUG-07 13:44:15	0.00		0.00		
DEC-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 03-JAN-08 08:07:01	0.00		0.00		
APR-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 27-APR-07 08:41:12		3,297.07	(3,297.07)		
SEP-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 28-SEP-07 08:12:09	0.00		0.00		
AUG-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 29-AUG-07 08:38:45	0.00		0.00		
JUN-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 29-JUN-07 11:31:30	3,297.07		3,297.07		
MAY-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 30-MAY-07 08:13:17		3,297.07	(3,297.07)		
NOV-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 30-NOV-07 08:26:08	0.00		0.00		
OCT-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 30-OCT-07 14:27:59	0.00		0.00		
JAN-07	0923	52010			J908 - Reverses "J960 Additional TEP/UNG/U Adjustment USD"12-FEB-07 09:15:31		143.90	(143.90)		
NOV-07	0923	52010			J916 Reclass Rate Case Co Adjustment USD	16,756.40		16,756.40		
OCT-07	0923	52010			J917 Write Down UNG Rate Adjustment USD	128,383.06		128,383.06		
SEP-07	0923	52010			J940 Adjust Rate Case Cos Adjustment USD	146,502.70		146,502.70		

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UNS Gas Legal Expenses - 2007

Company:032
Expenditure Type:152
BY FERC

GL Period	FERC	Acct	Pa Task Number	Pa Expenditure Comment	Gl JE Name	DR	CR	Net Amount	Invoice Number	Vendor Name
DEC-07	0923	52010			J975 Reverse 3rd Quarter Adjustment USD		31,000.00	(31,000.00)		
APR-07	0923	52010			Reverses "Accrual USD APR-07"24-APR-07 10:38:11		0.53	(0.53)		
AUG-07	0923	52010			Reverses "Accrual USD AUG-07"30-AUG-07 10:55:42		0.53	(0.53)		
DEC-07	0923	52010			Reverses "Accrual USD DEC-07"31-DEC-07 13:45:17		0.53	(0.53)		
FEB-07	0923	52010			Reverses "Accrual USD FEB-07"06-MAR-07 11:52:08		0.53	(0.53)		
JAN-07	0923	52010			Reverses "Accrual USD JAN-07"06-FEB-07 07:33:17		0.53	(0.53)		
JUL-07	0923	52010			Reverses "Accrual USD JUL-07"26-JUL-07 11:09:41		0.53	(0.53)		
JUN-07	0923	52010			Reverses "Accrual USD JUN-07"22-JUN-07 13:00:59		0.53	(0.53)		
MAR-07	0923	52010			Reverses "Accrual USD MAR-07"27-MAR-07 12:17:04		0.53	(0.53)		
MAY-07	0923	52010			Reverses "Accrual USD MAY-07"30-MAY-07 15:01:41		0.53	(0.53)		
NOV-07	0923	52010			Reverses "Accrual USD NOV-07"27-NOV-07 13:42:47		0.53	(0.53)		
OCT-07	0923	52010			Reverses "Accrual USD OCT-07"26-OCT-07 10:57:25		0.53	(0.53)		
SEP-07	0923	52010			Reverses "Accrual USD SEP-07"20-SEP-07 10:41:01		0.53	(0.53)		
		Sum				656,494.21	107,494.40	548,999.81		
Total						656,494.21	107,494.40	548,999.81		

Task	Task Description	
GTP0923	Admin & General Salaries	$13,010.60 A
GTPA160	Legal: El Paso Gas Allocation	$196,203.43
GTPD160	Legal: PGA Application	$3.00
GTPF160	Legal: UNSG Santa Cruz Gomez v. Cabrera, et al.	$52,918.35
GTPH160	Legal: Allstate v UES-Gas	$602.42
UNG06RC	UNS Gas Rate Case 2006	$307,303.51
	All other - JE, Accruals, Reversals	($21,041.50)
		$548,999.81
	2006 Rate Case - write off	$307,303.51 8a (3.2)
	Without Rate Case Write off	$241,696.30

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UNS Gas Legal Expenses - 2006

Company:032
Expenditure Type:152
BY FERC

GL Period	FERC	Acct	Pa Task Number	Pa Expenditure Comment	Gl JE Name	DR	CR	Net Amount	Invoice Number	Vendor Name
MAR-06	0923	52010	G560930		Purchase Invoices USD	55.36		55.36	RPC51257LUCERO	PETTY CASH
FEB-06	0923	52010	GTP0923		Purchase Invoices USD	2,233.75		2,233.75	0106 7052065	ROSHKA DEWULF & PATTEN PLC
APR-06	0923	52010	GTP0923		Purchase Invoices USD	1,386.60		1,386.60	0306 8497530	ROSHKA DEWULF & PATTEN PLC
APR-06	0923	52010	GTP0923		Purchase Invoices USD	$71.45		$71.45	764891	LEWIS AND ROCA LLP
MAY-06	0923	52010	GTP0923		Purchase Invoices USD	$453.20		$453.20	053106 5737731	ROSHKA DEWULF & PATTEN PLC
JUL-06	0923	52010	GTP0923		Purchase Invoices USD	$115.45		$115.45	770751	LEWIS AND ROCA LLP
JUL-06	0923	52010	GTP0923		Purchase Invoices USD	$26.62		$26.62	32803	ROSHKA DEWULF & PATTEN PLC
JUL-06	0923	52010	GTP0923		Purchase Invoices USD	$709.90		$709.90	6937776	THELEN REID BROWN RAYSMAN & STEINER LLP
AUG-06	0923	52010	GTP0923		Purchase Invoices USD	$2,589.90		$2,589.90	6940979	THELEN REID BROWN RAYSMAN & STEINER LLP
AUG-06	0923	52010	GTP0923		Purchase Invoices USD	$75.30		$75.30	773853	LEWIS AND ROCA LLP
SEP-06	0923	52010	GTP0923		Purchase Invoices USD	$2,574.37		$2,574.37	6944323	THELEN REID BROWN RAYSMAN & STEINER LLP
OCT-06	0923	52010	GTP0923		Purchase Invoices USD	825.00		825.00	33212	ROSHKA DEWULF & PATTEN PLC
OCT-06	0923	52010	GTP0923		Purchase Invoices USD	282.00		$282.00	32937	ROSHKA DEWULF & PATTEN PLC
NOV-06	0923	52010	GTP0923		Purchase Invoices USD	52.88		$52.88	781384	LEWIS AND ROCA LLP
NOV-06	0923	52010	GTP0923		Purchase Invoices USD	903.10		$903.10	33350	ROSHKA DEWULF & PATTEN PLC
DEC-06	0923	52010	GTP0923		Purchase Invoices USD	85.00		$85.00	33475	ROSHKA DEWULF & PATTEN PLC
DEC-06	0923	52010	GTP0923		Purchase Invoices USD	75.50		$75.50	785015	LEWIS AND ROCA LLP
JAN-06	0923	52010	GTPA160		Purchase Invoices USD	39,128.51		39,128.51	534850	FLEISCHMAN & WALSH LLP
FEB-06	0923	52010	GTPA160		Purchase Invoices USD	29,845.48		29,845.48	535137a	FLEISCHMAN & WALSH LLP
MAR-06	0923	52010	GTPA160		Purchase Invoices USD	29,845.48		29,845.48	535137	FLEISCHMAN & WALSH LLP
MAR-06	0923	52010	GTPA160		Purchase Invoices USD		29,845.48	(29,845.48)	535137a	FLEISCHMAN & WALSH LLP
MAR-06	0923	52010	GTPA160		Purchase Invoices USD	11,595.58		11,595.58	535457	FLEISCHMAN & WALSH LLP
APR-06	0923	52010	GTPA160		Purchase Invoices USD	6,050.00		6,050.00	578939	LOCKE LIDDELL & SAPP LLP
MAY-06	0923	52010	GTPA160		Purchase Invoices USD	30,806.84		30,806.84	584116	LOCKE LIDDELL & SAPP LLP
JUN-06	0923	52010	GTPA160		Purchase Invoices USD	43,278.93		43,278.93	588485	LOCKE LIDDELL & SAPP LLP
JUN-06	0923	52010	GTPA160		Purchase Invoices USD	43,545.07		43,545.07	591248	LOCKE LIDDELL & SAPP LLP
AUG-06	0923	52010	GTPA160		Purchase Invoices USD	38,875.06		38,875.06	596069	LOCKE LIDDELL & SAPP LLP
SEP-06	0923	52010	GTPA160		Purchase Invoices USD	39,214.58		39,214.58	599777	LOCKE LIDDELL & SAPP LLP
SEP-06	0923	52010	GTPA160		Purchase Invoices USD	38,130.60		38,130.60	603092	LOCKE LIDDELL & SAPP LLP
DEC-06	0923	52010	GTPA160		Purchase Invoices USD	38,828.60		38,828.60	611255	LOCKE LIDDELL & SAPP LLP
DEC-06	0923	52010	GTPA160		Purchase Invoices USD	35,947.61		35,947.61	607369	LOCKE LIDDELL & SAPP LLP
JAN-06	0923	52010	GTPD160		Purchase Invoices USD	17,612.56		17,612.56	1205 4752328	ROSHKA DEWULF & PATTEN PLC
FEB-06	0923	52010	GTPD160		Purchase Invoices USD	8,983.00		8,983.00	0106 7052065	ROSHKA DEWULF & PATTEN PLC
APR-06	0923	52010	GTPD160		Purchase Invoices USD	412.50		412.50	0306 8497530	ROSHKA DEWULF & PATTEN PLC
MAY-06	0923	52010	GTPD160		Purchase Invoices USD	508.50		508.50	053106 5737731	ROSHKA DEWULF & PATTEN PLC
OCT-06	0923	52010	GTPD160		Purchase Invoices USD	205.50		205.50	32937	ROSHKA DEWULF & PATTEN PLC
JUN-06	0923	52010	GTPF160		Purchase Invoices USD	1,575.00		1,575.00	050906 40642	BEALE MICHEAELS & SLACK PC
JUL-06	0923	52010	GTPF160		Purchase Invoices USD	267.13		267.13	071806 40642-0010	BEALE MICHEAELS & SLACK PC
JUL-06	0923	52010	GTPF160		Purchase Invoices USD	5,722.41		5,722.41	406420010061206	BEALE MICHEAELS & SLACK PC
SEP-06	0923	52010	GTPF160		Purchase Invoices USD	2,091.35		2,091.35	090606 209135	BEALE MICHEAELS & SLACK PC
OCT-06	0923	52010	GTPF160		Purchase Invoices USD	1,362.50		1,362.50	101106 40642-0010	BEALE MICHEAELS & SLACK PC
OCT-06	0923	52010	GTPF160		Purchase Invoices USD	1,267.24		1,267.24	092506 40642-0010	BEALE MICHEAELS & SLACK PC
NOV-06	0923	52010	GTPF160		Purchase Invoices USD	802.97		802.97	11581	INVESTIGATIVE RESEARCH INC
DEC-06	0923	52010	GTPF160		Purchase Invoices USD	5,838.43		5,838.43	111006 40640-0010	BEALE MICHEAELS & SLACK PC
NOV-06	0923	52010			Accrual USD DEC-06	0.54		0.54		
DEC-06	0923	52010			Accrual USD JAN-07	0.53		0.53		
OCT-06	0923	52010			Accrual USD NOV-06	0.54		0.54		
SEP-06	0923	52010			Accrual USD OCT-06	0.54		0.54		
AUG-06	0923	52010			Accrual USD SEP-06	0.54		0.54		
DEC-06	0923	52010			J341 - Legal Accrual Accrual USD		49,400.00	(49,400.00)		
DEC-06	0923	52000			J341 - Legal Accrual Accrual USD	13,000.00		13,000.00		

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UNS Gas Legal Expenses - 2006

Company:032
Expenditure Type:152
BY FERC

GL Period	FERC	Acct	Pa Task Number	Pa Expenditure Comment	Gl JE Name	DR	CR	Net Amount	Invoice Number	Vendor Name
JUN-06	0923	52010			J341 Legal Invoice Accrua	43,000.00		43,000.00		
SEP-06	0923	52010			J341 Legal Invoice Accrua	40,000.00		40,000.00		
FEB-06	0923	52010			J342 TEP/UNE/UNG Manual A	41,441.06		41,441.06		
NOV-06	0923	52010			J342 TEP/UNE/UNG Manual A	38,828.60		38,828.60		
DEC-06	0923	52010			J343 - Reverses "J342 TEP/UNE/UNG Manual A Adjustment		38,828.60	(38,828.60)		
MAR-06	0923	52010			J343 - Reverses "J342 TEP/UNE/UNG Manual A Adjustment		41,441.06	(41,441.06)		
JAN-06	0923	52010			J904 - Reverses "Reverses "J1015 Year End Accrual La Adjustment USD"07-FEB-06 08:39:45	17,612.56		17,612.56		
AUG-06	0923	52010			J906 UNS/TEP/UES Credit A		3,299.70	(3,299.70)		
SEP-06	0923	52010			J907 Correct coding of le Tax USD		2,574.37	(2,574.37)		
FEB-06	0923	52010			J909 - Reverses "J962 Jan-06 Inv. With Feb Adjustment USD"08-MAR-		41,062.23	(41,062.23)		
JAN-06	0923	52010			J925 - Reverses "J904 - Reverses "Reverses "J1015 Year End Accrual La Adjustment USD"07"08		17,612.56	(17,612.56)		
JAN-06	0923	52010			J926 Reverses J1015 A/P		17,612.56	(17,612.56)		
JAN-06	0923	52010			J932 - Reverses "J1020 Year End Accrual La Adjustment USD"14-FEB-		39,128.51	(39,128.51)		
DEC-06	0923	52010			J960 Additional TEP/UNG/U	143.90		143.90		
JAN-06	0923	52010			J962 Jan-06 Inv. With Feb	41,062.23		41,062.23		
DEC-06	0923	52010			Reverses "Accrual USD DEC-06"29-DEC-06 11:21:23		0.54	(0.54)		
NOV-06	0923	52010			Reverses "Accrual USD NOV-06"29-NOV-06 14:07:40		0.54	(0.54)		
OCT-06	0923	52010			Reverses "Accrual USD OCT-06"27-OCT-06 09:31:05		0.54	(0.54)		
SEP-06	0923	52010			Reverses "Accrual USD SEP-06"25-SEP-06 15:34:55		0.54	(0.54)		
	Sum					719,347.85	280,807.23	438,540.62		
Total						719,347.85	280,807.23	438,540.62		

Task	Task Description	
GTP0923	Admin & General Salaries	$12,460.02
GTPA160	Legal: El Paso Gas Allocation	$395,246.86
GTPD160	Legal: PGA Application	$27,722.06
GTPF160	Legal: UNSG Santa Cruz Gomez v. Cabrera, et al.	$18,927.03
	All other - JE, Accruals, Reversals	($15,815.35)
		$438,540.62

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UNS Gas Legal Expenses - 2005

Company:032
Expenditure Type:152
BY FERC

GL Period	FERC	Acct	Pa Task Number	Pa Expenditure Comment	Gl JE Name	DR	CR	Net Amount	Invoice Number	Vendor Name
MAY-05	0902	52010	G550902	OLSEN'S GRAIN		21.70		21.70		
	Sum					21.70		21.70		
MAR-05	0923	52010	G500921	TARGET 00009357		37.83		37.83		
JUL-05	0923	52010	G500921	TINKER & RASOR		$457.79		$457.79		
JAN-05	0923	52010	GTP0923		Purchase Invoices USD	$307.13		$307.13	719109	LEWIS AND ROCA LLP
JAN-05	0923	52010	GTP0923		Purchase Invoices USD	$19,216.41		$19,216.41	722228	LEWIS AND ROCA LLP
JAN-05	0923	52010	GTP0923		Purchase Invoices USD	$200.00		$200.00	200 0105	MARY L BONILLA ENDATED
JAN-05	0923	52010	GTP0923		Purchase Invoices USD	$18.00		$18.00	7740763	ROSHKA DEWULF & PATTEN PLC
JAN-05	0923	52010	GTP0923		Purchase Invoices USD	$600.00		$600.00	10313076	THELEN REID BROWN RAYSMAN & STEINER LLP
MAR-05	0923	52010	GTP0923		Purchase Invoices USD	$563.40		$563.40	5779900	ROSHKA DEWULF & PATTEN PLC
MAR-05	0923	52010	GTP0923		Purchase Invoices USD	$252.00		$252.00	30473	ROSHKA DEWULF & PATTEN PLC
MAR-05	0923	52010	GTP0923		Purchase Invoices USD	89.34		89.34	43056-00001 02/05	LEWIS AND ROCA LLP
APR-05	0923	52010	GTP0923		Purchase Invoices USD	180.00		$180.00	9856239	ROSHKA DEWULF & PATTEN PLC
APR-05	0923	52010	GTP0923		Purchase Invoices USD	111.35		$111.35	730641	LEWIS AND ROCA LLP
MAY-05	0923	52010	GTP0923		Purchase Invoices USD	7,616.25		$7,616.25	6884398	THELEN REID BROWN RAYSMAN & STEINER LLP
JUN-05	0923	52010	GTP0923		Purchase Invoices USD	13,411.45		$13,411.45	6887902	THELEN REID BROWN RAYSMAN & STEINER LLP
JUN-05	0923	52010	GTP0923		Purchase Invoices USD	133.75		$133.75	43056-00001 05/05	LEWIS AND ROCA LLP
JUL-05	0923	52010	GTP0923		Purchase Invoices USD	216.00		216.00	6835245 06/05	ROSHKA DEWULF & PATTEN PLC
JUL-05	0923	52010	GTP0923		Purchase Invoices USD	3.75		3.75	6895440	THELEN REID BROWN RAYSMAN & STEINER LLP
SEP-05	0923	52010	GTP0923		Purchase Invoices USD	40.80		40.80	1092930 081505	LEWIS AND ROCA LLP
OCT-05	0923	52010	GTP0923		Purchase Invoices USD	297.80		297.80	12079283 0805	ROSHKA DEWULF & PATTEN PLC
OCT-05	0923	52010	GTP0923		Purchase Invoices USD	1,928.24		1,928.24	10178709 100105	ROSHKA DEWULF & PATTEN PLC
OCT-05	0923	52010	GTP0923		Purchase Invoices USD	313.61		313.61	694353 100105	LEWIS AND ROCA LLP
NOV-05	0923	52010	GTP0923		Purchase Invoices USD	396.00		396.00	1005 11237055	ROSHKA DEWULF & PATTEN PLC
DEC-05	0923	52010	GTP0923		Purchase Invoices USD	139.20		139.20	1005 78240	LEWIS AND ROCA LLP
DEC-05	0923	52010	GTP0923		Purchase Invoices USD	1,662.40		1,662.40	1105 5888581	ROSHKA DEWULF & PATTEN PLC
FEB-05	0923	52010	GTP0923				18,866.48	(18,866.48)		
JAN-05	0923	52010	GTPA160		Purchase Invoices USD	6,248.77		6,248.77	531564	FLEISCHMAN & WALSH LLP
MAR-05	0923	52010	GTPA160		Purchase Invoices USD	19,887.55		19,887.55	532093	FLEISCHMAN & WALSH LLP
APR-05	0923	52010	GTPA160		Purchase Invoices USD	19,482.02		19,482.02	532341	FLEISCHMAN & WALSH LLP
APR-05	0923	52010	GTPA160		Purchase Invoices USD	19,083.78		19,083.78	531797	FLEISCHMAN & WALSH LLP
MAY-05	0923	52010	GTPA160		Purchase Invoices USD	87,268.56		87,268.56	532735	FLEISCHMAN & WALSH LLP
JUN-05	0923	52010	GTPA160		Purchase Invoices USD		720.00	(720.00)	351816	THELEN REID BROWN RAYSMAN & STEINER LLP
JUN-05	0923	52010	GTPA160		Purchase Invoices USD	11,030.00		11,030.00	532812	FLEISCHMAN & WALSH LLP
JUL-05	0923	52010	GTPA160		Purchase Invoices USD	14,299.22		14,299.22	533248	FLEISCHMAN & WALSH LLP
AUG-05	0923	52010	GTPA160		Purchase Invoices USD	28,463.40		28,463.40	533381	FLEISCHMAN & WALSH LLP
SEP-05	0923	52010	GTPA160		Purchase Invoices USD	56,611.88		56,611.88	533691	FLEISCHMAN & WALSH LLP
OCT-05	0923	52010	GTPA160		Purchase Invoices USD	32,330.68		32,330.68	3233068 0805	FLEISCHMAN & WALSH LLP
NOV-05	0923	52010	GTPA160		Purchase Invoices USD	28,712.29		28,712.29	534292	FLEISCHMAN & WALSH LLP
DEC-05	0923	52010	GTPA160		Purchase Invoices USD	38,534.74		38,534.74	534589	FLEISCHMAN & WALSH LLP
MAR-05	0923	52010	GTPD160		Purchase Invoices USD	386.00		386.00	30473	ROSHKA DEWULF & PATTEN PLC
APR-05	0923	52010	GTPD160		Purchase Invoices USD	11,201.01		11,201.01	9856239	ROSHKA DEWULF & PATTEN PLC
JUN-05	0923	52010	GTPD160		Purchase Invoices USD	11,234.83		11,234.83	MAY-05	ROSHKA DEWULF & PATTEN PLC
JUN-05	0923	52010	GTPD160		Purchase Invoices USD	2,490.20		2,490.20	233 05/05	ROSHKA DEWULF & PATTEN PLC
JUL-05	0923	52010	GTPD160		Purchase Invoices USD	360.00		360.00	6835245 06/05	ROSHKA DEWULF & PATTEN PLC
OCT-05	0923	52010	GTPD160		Purchase Invoices USD	2,304.50		2,304.50	12079283 0805	ROSHKA DEWULF & PATTEN PLC
OCT-05	0923	52010	GTPD160		Purchase Invoices USD	3,411.86		3,411.86	10178709 100105	ROSHKA DEWULF & PATTEN PLC
NOV-05	0923	52010	GTPD160		Purchase Invoices USD	15,277.45		15,277.45	1005 11237055	ROSHKA DEWULF & PATTEN PLC
DEC-05	0923	52010	GTPD160		Purchase Invoices USD	22,236.08		22,236.08	1105 5888581	ROSHKA DEWULF & PATTEN PLC
OCT-05	0923	52010	GTPF160		Purchase Invoices USD	462.00		462.00	6594	BOULEY & SCHIPPERS
DEC-05	0923	52010	GTPF160		Purchase Invoices USD	228.00		228.00	6728	BOULEY & SCHIPPERS

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UNS Gas Legal Expenses - 2005

Company:032
Expenditure Type:152
BY FERC

GL Period	FERC	Acct	Pa Task Number	Pa Expenditure Comment	Gl JE Name	DR	CR	Net Amount	Invoice Number	Vendor Name
DEC-05	0923	52010			J1015 Year End Accrual La Adjustment USD	17,612.56		17,612.56		
DEC-05	0923	52010			J1020 Year End Accrual La Adjustment USD	39,128.51		39,128.51		
APR-05	0923	52010			J342 TEP/UNE/UNG Manual A Adjustment USD	87,268.56		87,268.56		
APR-05	0923	52010			J901 - Reverses "J930 TEP/UNE/UNG Manual A Adjustment USD"28-APR-05 09:19:07		111.00	(111.00)		
MAY-05	0923	52010			J902 - Reverses "J342 TEP/UNE/UNG Manual A Adjustment USD"31-MAY-05 11:06:06		87,268.56	(87,268.56)		
MAY-05	0923	52010			J905 Capitalize Debt-rela Adjustment USD		7,616.25	(7,616.25)		
MAY-05	0923	52010			J906 Reverse Dec 2004 J34 Adjustment USD		349.93	(349.93)		
JUN-05	0923	52010			J908 - Correct Recording Tax USD		13,411.45	(13,411.45)		
JAN-05	0923	52010			J909 - Reverses "J933 TEP/UNE/UNG Manual A Adjustment USD"03-FEB-05 16:33:57		246,924.07	(246,924.07)		
JAN-05	0923	52010			J922 UNSE/UNSG Correction Adjustment USD	239,768.17		239,768.17		
MAR-05	0923	52010			J930 TEP/UNE/UNG Manual A Adjustment USD	111.00		111.00		
	Sum					863,626.12	375,267.74	488,358.38		
Total						863,647.82	375,267.74	488,380.08		

Task	Task Description	
GTP0923	Admin & General Salaries	$28,830.40 A
GTPA160	Legal: El Paso Gas Allocation	$361,232.89
GTPD160	Legal: PGA Application	$68,901.93
GTPF160	Legal: UNSG Santa Cruz Gomez v. Cabrera, et al.	$690.00
	All other - JE, Accruals, Reversals	$28,724.86
		$488,380.08

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UNS Gas, Inc.
Payroll Adjustment
Test Year Ended June 30, 2008

FERC Account	Data for the Test Year Ending June 30, 2008: TY 06/2008 Regular Wages Per Books	% Of TY 06/2008 Regular Wages	TY 06/2008 Overtime	% Of TY 06/2008 Overtime Wages	TY 06/2008 Allocated From CLR Accts	% Of TY 06/2008 Allocated From CLR Accts	(A) Total Wages Recorded by UNSG in CLR Accts	Adjusted Payroll - Annualized and Increased for 2009 & 2010 wage increase: Regular Annualized Payroll As of July 2008	2009 & 2010 Wage Increase	Adjusted Overtime	Estimate Allocated From CLR Accts	(B) Total Adjusted Payroll With Overtime	(B-A) Payroll Adjustment
Classified													
Operations - Gas													
Transmission													
0870 Trans-Oper Supervision & Engr	3A 72.95	0.00%	6A 21,166.22	3.11%	9.66	0.00%	21,248.83	71.08	75.41	24,743.12	10.01	24,828.53	3,580
Distribution													
0874 Dist-Mains & Services Exp — 5b	430,747.35	4.46%	51,918.49	7.63%	57,013.18	7.38%	539,679.02	419,685.58	445,244.44	60,692.24	59,107.16	565,043.83	25,365
0875 Dist-Meas & Reg Station Exp-Gen	15,511.75	0.16%	545.06	0.08%	2,063.12	0.27%	18,109.93	15,113.40	16,033.81	637.17	2,128.52	18,799.50	690
0876 Dist-Meas & Reg Station Exp-Ind	0.00	0.00%	118.74	0.02%	-	0.00%	118.74	-	-	138.81	-	138.81	20
0877 Dist-Meas & Reg Station Exp-CtGt	13,453.52	0.14%	748.43	0.11%	1,760.89	0.23%	15,982.64	13,108.03	13,906.31	874.91	1,846.09	16,627.31	645
0878 Dist-Meter Exp — 5b +	780,846.87	8.08%	163,457.09	24.02%	103,351.92	13.37%	1,047,655.88	760,794.41	807,126.78	191,079.83	107,147.83	1,105,354.44	57,699
0879 Dist-Customer Installations Exp +	373,188.44	3.86%	205,601.35	30.21%	49,394.78	6.39%	628,184.55	363,604.81	385,748.34	240,348.08	51,208.93	677,303.35	49,119
0880 Dist-Other Expenses +	174,838.41	1.81%	14,675.62	2.16%	23,114.92	2.99%	212,428.95	170,153.62	180,515.98	17,155.66	23,963.89	221,635.53	9,207
Customer Accounting													
0902 Meter Reading Expense +	428,519.93	4.43%	73,138.08	10.75%	56,718.37	7.34%	558,378.38	417,515.36	442,942.05	85,497.74	58,801.51	587,241.30	28,863
0903 Cust Rec/Collection Exp — 5.1e +	486,854.27	5.04%	53,671.99	7.89%	64,439.43	8.34%	604,965.69	474,351.65	503,239.67	62,742.06	66,806.15	632,787.88	27,822
0905 Misc Customer Accts Exp	238.29	0.00%	-	0.00%	31.54	0.00%	269.83	232.17	246.31	-	32.70	279.01	9
Customer Service & Information													
0908 Customer Assistance Exp	13,796.80	0.14%	-	0.00%	1,826.13	0.24%	15,622.93	13,442.49	14,261.14	-	1,893.20	16,154.34	531
Administration & General													
0920 A&G Salaries	18,737.01	0.19%	181.10	0.03%	2,480.01	0.32%	21,398.12	18,255.84	19,367.62	211.70	2,571.09	22,150.41	752
0925 Injuries & Damages	25,599.10	0.26%	-	0.00%	3,388.27	0.44%	28,987.37	24,941.70	26,460.65	-	3,512.71	29,973.36	986
0926 Pensions & Benefits	227.50	0.00%	18,362.50	2.70%	30.11	0.00%	18,620.11	221.66	235.16	21,466.59	31.22	21,731.97	3,112
0930 General Advertising Exp	793.04	0.01%	174.81	0.03%	104.97	0.01%	1,072.82	772.67	819.73	204.35	108.82	1,132.90	60
Total Operations	2,763,225.23	28.60%	603,759.48	88.71%	365,737.06	47.33%	3,732,721.77	2,692,284.48	2,856,223.39	705,789.26	379,169.83	3,941,182.48	208,461
Maintenance - Gas													
Distribution													
0885 Dist-Maint Supervision & Engr	0.00	0.00%	-	0.00%	-	0.00%	-	-	-	-	-	-	0
0887 Dist-Maint of Mains — 5b +	140,871.14	1.46%	41,494.77	6.10%	18,645.53	2.41%	201,011.44	137,253.51	145,612.25	48,507.00	19,330.34	213,449.59	12,438
0889 Dist-Maint Meas & Reg Station Equip-Gen	5,000.64	0.05%	1,084.97	0.16%	661.88	0.09%	6,747.49	4,872.22	5,168.94	1,268.32	686.19	7,123.45	376
0890 Dist-Maint Meas & Reg Station Equip-Ind	0.00	0.00%	-	0.00%	-	0.00%	-	-	-	-	-	-	0
0891 Dist-Maint Meas & Reg Station Exp-CtGt	522.28	0.01%	110.76	0.02%	69.13	0.01%	702.17	508.87	539.86	129.48	71.67	741.00	39
0892 Dist-Maint of Services — 5b +	129,704.07	1.34%	30,441.13	4.47%	17,167.47	2.22%	177,312.67	126,373.22	134,069.35	35,585.40	17,798.00	187,452.74	10,140
0893 Dist-Maint of Meters — 5b +	74,871.22	0.77%	3,271.65	0.48%	9,909.86	1.28%	88,052.73	72,948.50	77,391.06	3,824.53	10,273.83	91,489.42	3,437
0894 Dist-Maint of Other Equipment	2,235.94	0.02%	419.00	0.06%	295.95	0.04%	2,950.89	2,178.52	2,311.19	489.81	306.82	3,107.81	157
Administrative & General													
0932 Dist-Maint of General Plant	5,837.07	0.06%	31.83	0.00%	772.59	0.10%	6,641.49	5,687.17	6,033.52	37.21	800.98	6,871.69	230
Total Maintenance	359,042.36	3.72%	76,854.11	11.29%	47,522.40	6.15%	483,418.87	349,822.01	371,126.17	89,841.74	49,267.80	510,235.71	26,817
Total Operations & Maintenance - CLS	3,122,267.59 = 3B	32.31%	680,613.59	1.00	413,259.47 13a	53.48%	4,216,140.65	3,042,066.49	3,227,349.56	$795,631.00 2A	428,437.63	4,451,418.19	235,278
Unclassified													
Operations - Gas													
Transmission													
0856 Trans-Mains Exp	4A 7,755.85	0.08%	7A 730.28	0.76%	1,026.55	0.13%	9,512.68	7,556.66	8,016.88	897.68	1,064.26	9,978.82	466
0857 Trans-Meas & Reg Station Exp	0.00	0.00%	-	0.00%	-	0.00%	-	-	-	-	-	-	0
0870 Trans-Oper Supervision & Engr — 5.1f +	193,118.12	2.00%	-	0.00%	25,560.87	3.31%	218,678.99	188,158.77	199,617.64	-	26,499.67	226,117.31	7,438
Distribution													
0874 Dist-Mains & Services Exp	411,826.06	4.26%	11,626.74	12.05%	54,508.79	7.06%	477,961.59	401,250.20	425,686.34	14,291.92	56,510.78	496,489.04	18,527
0875 Dist-Meas & Reg Station Exp-Gen — 5.1f +	105,108.91	1.09%	1,996.81	2.07%	13,912.06	1.80%	121,017.80	102,409.67	108,646.42	2,454.54	14,423.06	125,524.00	4,506
0876 Dist-Meas & Reg Station Exp-Ind	110,461.57	1.14%	2,652.76	2.75%	14,620.56	1.89%	127,734.89	107,624.87	114,179.23	3,260.85	15,157.54	132,597.61	4,863
0877 Dist-Meas & Reg Station Exp-CtGt	3,955.85	0.04%	273.71	0.28%	523.59	0.07%	4,753.15	3,854.26	4,088.99	336.45	542.82	4,968.28	215
0878 Dist-Meter Exp	1,606.88	0.02%	-	0.00%	212.68	0.03%	1,619.56	1,565.61	1,660.96	-	220.50	1,681.46	62
0879 Dist-Customer Installations Exp — 5.1f +	7,666.82	0.08%	771.21	0.80%	1,014.77	0.13%	9,452.80	7,469.93	7,924.85	947.99	1,052.04	9,924.89	472
0880 Dist-Other Expenses	195,919.44	2.03%	2,001.49	2.07%	25,931.65	3.36%	223,852.58	190,888.15	202,513.24	2,460.29	26,884.07	231,857.60	8,005
Customer Accounting													
0901 Cust Accounting-Supervision	3,270.50	0.03%	-	0.00%	432.88	0.06%	3,703.38	3,186.51	3,380.57	-	448.78	3,829.35	126
0902 Meter Reading Expense	74,573.45	0.77%	18,032.59	18.69%	9,870.45	1.28%	102,476.49	72,658.37	77,083.27	22,166.18	10,232.97	109,482.41	7,006
0903 Cust Rec/Collection Exp +	107,755.69	1.12%	-	0.00%	14,262.41	1.85%	122,018.10	104,988.48	111,382.28	-	14,786.24	126,168.52	4,150

905 - misc. Cust. Accts

UNSG0571/02585

UNS Gas, Inc.
Payroll Adjustment
Test Year Ended June 30, 2008

FERC Account	Data for the Test Year Ending June 30, 2008: TY 06/2008 Regular Wages Per Books	% Of TY 06/2008 Regular Wages	TY 06/2008 Overtime	% Of TY 06/2008 Overtime Wages	TY 06/2008 Allocated From CLR Accts	% Of TY 06/2008 Allocated From CLR Accts	(A) Total Wages Recorded by UNSG in CLR Accts	Adjusted Payroll - Annualized and Increased for 2009 & 2010 wage increase: Regular Annualized Payroll As of July 2008	2009 & 2010 Wage Increase	Adjusted Overtime	Estimate Allocated From CLR Accts	(B) Total Adjusted Payroll With Overtime	(B-A) Payroll Adjustment
Customer Service & Information													
0908 Customer Assistance Exp	1,805.54	0.02%	-	0.00%	238.98	0.03%	2,044.52	1,759.17	1,866.31	-	247.78	2,114.06	70
0910 Misc Cust Service/Info Exp	0.00	0.00%	-	0.00%	-	0.00%	-	-	-	-	-	-	0
Administration & General													
0920 A&G Salaries	982,694.93	10.17%	1,881.10	1.95%	130,068.28	16.83%	1,114,644.31	957,458.93	1,015,768.17	2,312.30	134,845.42	1,152,925.90	38,282
0925 Injuries and Damages	7,720.57	0.08%	-	0.00%	1,021.89	0.13%	8,742.46	7,522.30	7,980.41	-	1,059.42	9,039.83	297
0930 General Advertising Exp	241.54	0.00%	-	0.00%	31.97	0.00%	273.51	235.34	249.67	-	33.14	282.81	9
Total Operations	2,215,481.72	22.93%	39,966.89	41.42%	293,238.41	37.95%	2,548,686.82	2,158,587.25	2,290,045.21	49,128.20	304,008.45	2,643,181.86	94,495
Maintenance - Gas													
Production													
0554 Maint of Misc Oth Pwr Gen Plant	0.00	0.00%	-	0.00%	-	0.00%	-	-	-	-	-	-	0
Distribution													
0885 Dist-Maint Supervision & Engr	151,848.12	1.57%	-	0.00%	20,098.43	2.60%	171,946.55	147,948.60	156,958.67	-	20,836.60	177,795.27	5,849
0887 Dist-Maint of Mains	191,890.46	1.99%	31,929.70	33.09%	25,398.38	3.29%	249,218.54	186,962.64	198,346.86	39,248.90	26,331.21	263,928.77	14,710
0889 Dist-Maint Meas & Reg Station Equip-Gen	4,125.38	0.04%	387.24	0.40%	546.03	0.07%	5,058.65	4,019.44	4,264.22	476.01	566.08	5,306.31	248
0891 Dist-Maint Meas & Reg Station Exp-CtGt	1,023.98	0.01%	203.32	0.21%	135.53	0.02%	1,362.83	997.68	1,058.44	249.93	140.51	1,448.88	86
0892 Dist-Maint of Services	138,446.66	1.43%	23,600.44	24.46%	18,324.63	2.37%	180,371.73	134,891.29	143,106.17	29,010.34	18,997.65	191,114.16	10,742
0893 Dist-Maint of Meters	7,443.18	0.08%	408.90	0.42%	985.17	0.13%	8,837.25	7,252.04	7,693.69	502.63	1,021.35	9,217.67	380
0894 Dist-Maint of Other Equipment	1,259.60	0.01%	-	0.00%	166.72	0.02%	1,426.32	1,227.25	1,301.99	-	172.84	1,474.84	49
Administrative & General													
0932 Dist-Maint of General Plant	4,713.89	0.05%	-	0.00%	623.92	0.08%	5,337.81	4,592.84	4,872.54	-	646.84	5,519.38	182
Total Maintenance	500,751.27	5.18%	56,529.60	58.58%	66,278.82	8.58%	623,559.69	487,891.77	517,604.38	69,487.80	68,713.10	655,805.29	32,246
Total Operations & Maintenance - UNC	2,716,232.99	28.11%	96,496.29	100.00%	359,517.23	46.52%	3,172,246.51	2,646,479.02	2,807,649.60	$118,616.00	372,721.55	3,298,987.15	126,741
Total O&M Wages	Ⓐ 5,838,500.58	60.42%	777,109.88		772,776.70	100.00%	7,388,387.16	5,688,565.51	6,034,999.15 Ⓑ	914,247.00	801,159.18	② 7,750,406.34	362,018
Wages Charged to Other Accounts	Ⓒ 3,824,744.05	39.58%	243,570.51		(772,776.70)	-100.00%	3,295,537.86	3,726,523.07	3,953,468.32 Ⓓ	264,267.00	(801,159.18)	① 3,416,576.14	
Total Payroll	9,663,244.63	100.00%	1,020,680.39		-	0.00%	10,683,925.02	9,415,088.58	9,988,467.48	1,179,514.00	-	③ 11,166,981.48	
	(1)		(1)		(2)			(3)		(4)	(5)		

0.063682826

3% - 2009 Rate Increase	1.03
	9,697,541.24
3% - 2010 Rate Increase	1.03
(6)	9,988,467.48

14a

①/③ = 30.59% to Capital
②/③ = 69.41% to O&M

Notes:
(1) Ties to Classified and Unclassified Distribution based on system generated Payroll by Function Reports
(2) Based on Clearing Account Allocation
(3) Represents UNSG's regular payroll as of July 2008 obtained from Payroll - Total spread to Classified/Unclassified/Wages charged to other account based on % of TY 06/08 regular wages.
(4) The overtime rate represents a 2-year average (TME 6-2007 & 6-2008) increased for the 2009 & 2010 wage rate increase
Total spread based on % of TY 06/08 overtime by Classified/Unclassified/Non-O&M.
(5) Based on percentage of Total Wages Charged to Other Accounts and then allocated to O&M in Test Year
(6) Annualized Payroll adjusted for a 3% wage increase in 2008 & 2009

1.1

UNS Gas, Inc.
Payroll Tax Adjustment
Pro Forma Payroll Taxes
Test Year Ended June 30, 2008

Social Security Tax:

(a) Medicare -		
UNSG Estimated 2009/2010 Payroll - including OT	$11,166,981 4.1a ✓	
Medicare Tax Base	$11,166,981 4.1a ✓	
Medicare Tax Rate (%)	1.45 8b ✓	
Pro Forma Medicare Tax		$161,921 ✓ a
(b) OASDI -		
UNSG Regular Annualized Payroll - Including OT	$11,166,981 4.1a ✓	
Less: Wages in Excess of $102,000 ✓ - 8a - UNSG Unclassified	(99,577.18) 7.2a ✓	
OASDI Tax Base	$11,067,404 ✓	
OASDI Tax Rate (%)	6.20 8a ✓	
Pro Forma OASDI Tax		$686,179 ✓

Federal/State Unemployment Tax:

Number of Employees -		
UNSG Classified	7.1a 118 ✓	
UNSG Unclassified	7.2b 86 ✓	
Total Employees	204 ✓	
Taxable Wages ($)	8.1a 7,000 ✓	
Tax Base	1,428,000 ✓	
Tax Rate (%)	2.80 8c ✓	
Pro Forma FUI/SUI		$39,984 ✓
Total Pro Forma Payroll Taxes		$888,084 F

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Attachment RCS-6
Copies of Confidential UNS Gas' Responses to Data Requests and Workpapers Referenced in the Direct Testimony and Schedules of Ralph C. Smith

****UNS Gas Confidential Pages Have Been Redacted****

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
RUCO 1.46	Amounts of incentive compensation expense included in the test year	Yes	5	2-6
Attachment TF 6.46	UES Results of Operations - Year end 2008	Yes	2	7-8
Attachment TF 6.92	Incentive compensation programs (2008 long-term program term sheet)	Yes	2	9-10
	Total Pages Including this Page		10	

PAGES 2-10 ARE CONFIDENTIAL AND HAVE BEEN REDACTED